PLAN APPROVAL APPLICATION

Philadelphia Energy Solutions Refining and Marketing, LLC. (PES).

Supplement to Plan Approval Application Package for Heater Firing Rate Increase

August 31, 2012 (Submittal)
September 6, 2012 (Completeness Determination)
September 2013 (Supplement)

Environmental Resources Management
75 Valley Stream Parkway
Suite 200
Malvern, Pennsylvania 19355

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1.0 INTRODUCTION & OVERALL SUMMARY

Philadelphia Energy Solutions Refining and Marketing, LLC (PES) owns and operates a petroleum refinery in Philadelphia, Pennsylvania. The Philadelphia Refinery (Refinery) consists of multiple processing areas, the Girard Point Processing Area (GP) near the Platt Bridge, the Point Breeze Processing Area (PB) located near the Passyunk Avenue Bridge, and permanently closed crude refining operations at Marcus Hook. The Refinery is made up of a number of processing units that are employed in the overall process of converting crude petroleum and other hydrocarbon feed stocks into finished hydrocarbon products and petrochemicals. Products include gasoline, home heating oil, diesel fuel and others.

PES is submitting this supplement to the Plan Approval application[1] to request approval for increase in the firing rate of seven target process heaters at the Refinery to facilitate a shift in production as a part of a strategic plan to shift crude oil refining operations to GP and PB and away from Marcus Hook. This supplement is provided in response to comments and questions from reviewing agencies. Since some of the comments were about clarity in the application, some content has been expanded and reorganized. As such, this supplement is provided in the form of a complete application package.

This plan approval seeks to increase the firing limitations of the seven target process heaters. This will help in shifting production from the shutdown Marcus Hook operations. In fact, this plan approval includes application of emission netting credits (emission reductions) that result in overall decreases for certain pollutants from the combined Philadelphia and Marcus Hook operations. Specifically, following this plan approval, there will be an **estimated net decrease** in emissions of 55.9 tons per year (TPY) of nitrogen oxides (NO_x)[2].

All Refinery processing units rely on the combustion of refinery fuel gas (consisting of a combination of refinery by-product gas and natural gas) in direct-fired process heaters and steam-producing boilers to provide the energy needed to drive hydrocarbon conversions and product

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[1] Sunoco, Inc. originally submitted this Plan Approval application on August 31, 2012. PES took over ownership of the Refinery on September 8, 2012. PES submitted an updated Plan Approval application that included corrected data and other revisions requested by Philadelphia Air Management Services (AMS) on November 13, 2012. PES submits this further revision to the Plan Approval application in response to further comments from USEPA, AMS and Pennsylvania DEP.

[2] NO_x (TPY): increase = 140.1, credits applied = 195.9, overall reduction: 140.1 – 195.9 = 55.9.

separations. By this application, the Refinery is proposing to increase the firing limits on seven of its Philadelphia process heaters. This will allow the Refinery to process, on average, more crude into finished products, subject to other permit restrictions on various units. Specifically, this change will enable the Refinery to offset reductions of intermediate streams feeding Refinery processes that were previously provided to the Refinery from the Marcus Hook operations.

This application lays out the emissions analyses and regulatory impacts from the permit limit changes requested for the seven target heaters, including impacts on ancillary operations at the Refinery.

1.1 SINGLE SOURCE DETERMINATION

On August 7, 2012, the Pennsylvania Department of Environmental Protection (PADEP) issued an amendment to the Title V permit for the Marcus Hook Refinery, and Philadelphia Air Management Services (AMS) issued an administrative order for the Title V permit for the Philadelphia Refinery recognizing that the two locations were a single source, for the reasons set forth therein. Sunoco's retirement on August 15, 2012, of the permits for operating crude refining sources at the former Marcus Hook Refinery implemented the plan to shift that production to the Philadelphia Refinery as a part of the shutdown of crude refining operations at the Marcus Hook Refinery.

1.2 SETTLEMENT WITH CLEAN AIR COUNCIL

On April 19, 2013, PES and the Clean Air Council (CAC) reached a settlement resolving CAC's appeal of the PADEP decision allowing emission reductions from the shut-down of the former Sunoco Inc. Marcus Hook Refinery to be credited to the Philadelphia Refining Complex, which PES obtained from Sunoco Inc. in September 2012.

As part of this settlement, PES agreed voluntarily to install ultra-low NO_x burners (ULNB) on the Unit 231-B101 Heater and Unit 865-11H1 Heater at the Refinery to further reduce emissions beyond the cuts achieved by the shut-down of the Marcus Hook Refinery. These ULNB are to be installed only upon approval of higher firing rates as discussed in this plan approval application.

1.3 *PROPOSED PERMITTING*

Other than the installation of ULNBs on Unit 231-B101 and Unit 865-11H1, there are no physical changes to the seven target heaters as a result of this project to increase firing rates. Moreover, the firing rates on the target heaters are limited by existing Reasonably Achievable Control Technology (RACT) requirements. To accommodate the increase in firing rates on the target heaters, PES is requesting revisions to the firing rate limits established as a part of the RACT permit (See Attachment A).

This Plan Approval application package includes the following:

- Detailed plan approval descriptions (Section 2.0);
- Air emission changes associated with the plan approval (Section 3.0);
- New Source Review (NSR) applicability analysis (Section 4.0);
- Best Available Control Technology (BACT) analysis for CO control (Section 5.0);
- Other Federal and State applicability analysis (Section 6.0); and
- Proposed permit conditions (Section 7.0).

Attachments to this Plan Approval application package include the following:

- Reasonably Achievable Control Technology (RACT) analysis (Attachment A);
- AMS Plan Approval Application forms (Attachment B);
- Compliance Review History (Attachment C);
- Emission Calculations (Attachment D);
- Process Flow Diagrams/Site Location Map (Attachment E);
- CO Dispersion Modeling (Attachment F);
- RBLC and BAAQMD BACT Search Results (Attachment G);
- CO Cost Effectiveness Analysis (Attachment H); and

- BAT Cost Effectiveness Analysis (Attachment I).

2.0 PLAN APPROVAL OVERVIEW

PES submits this plan approval application in order to allow the Philadelphia Refinery to accommodate increased production. It is necessary to increase the firing limitations of the seven target process heaters to enable an overall production increase and thus offset decreases in production from Marcus Hook operations.

The changes to the target heaters and the effects on ancillary Refinery sources are discussed in the sections that follow.

2.1 TARGET HEATERS

Other than the installation of ULNBs on Unit 231-B101 and Unit 865-11H1, this project will not involve any physical changes to the target heaters. PES is seeking to remove the hourly average firing limits (million British thermal units per hour [MMBtu/hr]) of the target heaters and replace them with annual average firing limits (MMBtu/year). The new annual average firing rate limits are based on increases in the hourly average firing limits. The existing hourly firing limits and proposed annual firing limits for the heaters are shown in Table 2-1 below.

Table 2-1 Proposed Firing Limits for Target Heaters

Process Unit	Heater	Existing Hourly Firing Limit (MMBtu/hr)[1]	Proposed Annual Firing Limit (MMBtu/year)[2]
GP Unit 231 HDS	B101 Feed Heater	91.0	856,000
PB Unit 865 HDS	11H1 Feed Heater	72.2	699,000
PB Unit 865 HDS	11H2 Reboiler Heater	49.9	500,000
PB Unit 210 Crude	H101 Crude Heater	183.0	1,643,000
PB Unit 210 Crude	H201 Crude Heater	242.0	2,172,000
PB Unit 866 HDS	12H1 Feed Heater	43.0	456,000
PB Unit 868 FCCU	8H101 Recycle Heater	49.5	480,000

[1] Compliance determined on a daily average basis.
[2] Compliance determined on a rolling 365-day average basis.

2.2 *SHUTDOWN SOURCES AT MARCUS HOOK REFINERY*

Sunoco's retirement on August 15, 2012, of the permits for operating crude refining sources at the former Marcus Hook Refinery was contemporaneous with a filing by the Sunoco Philadelphia Refinery[3] for emission reduction credits (ERCs) for the shutdown units listed below.

The shutdown sources at the Marcus Hook Refinery include[4]:

- Unit 12-3 Crude Heater H-3006;
- Unit 17-2A H-01, H-02, H-03 Heater;
- Unit 12-3 Crude Desulf Heater;
- Unit 15-1 Crude Heater;
- Unit 17-2A H-04 Heater; and
- Marcus Hook Cooling Towers including the 10 Plant A and B, 12 Plant North and South, 17-1A, 17-2, 17-2A and LSG towers.

The ERCs generated by the shutdown units listed above are included as contemporaneous emissions reductions. See Section 4.2 for details on the contemporaneous emissions analysis.

2.3 *UPSTREAM/DOWNSTREAM ANCILLARY UNITS*

The annual firing rate limits sought for the target heaters are expected to allow for increased utilization of upstream/downstream ancillary units relative to the 2010-2011 baseline period.

As discussed in Section 3, the emissions increases associated with the upstream/downstream ancillary units are estimated based on potential incremental increase in crude throughput in the future. PES has estimated the future potential incremental increase in crude throughput at the

[3] The Sunoco Philadelphia Refinery is now owned and operated by Philadelphia Energy Solutions Refining and Marketing, LLC (PES).

[4] The sources shutdown listed here do not include shutdown sources listed in Consent Decree No. 05-02866 (Fourth Amendment, dated August 17, 2012). The sources listed in the Consent Decree are subject to specific requirements.

Philadelphia Refinery that is expected as a result of this plan approval and the shutdown of the Marcus Hook Refinery.

Figures 2-1 and 2-2 at the end of this section show the overall process flow diagrams for the Girard Point and Point Breeze Processing Areas.

The Refinery is designed such that process units can run on a combination of feedstocks – those produced on site through distillation and other Refinery units – as well as imported feedstocks. Feedstocks are imported from a number of outside sources, which included, prior to shutdown of operating units, the Marcus Hook Refinery. The types and amounts of imported feedstocks vary based on a number of factors, including economic drivers and overall product demand.

This plan approval will enable upstream and downstream ancillary units to operate with a greater portion of their feeds from other materials processed at the Refinery, thus offsetting feed materials previously available from the Marcus Hook operations. Prior to shutdown of operating units at Marcus Hook, the typical imports of Marcus Hook produced components to Philadelphia operations included the following:

- Butanes – Marcus Hook provided about 1 thousand barrels per day (MBPD) of Butane/Butylene mix as incremental feed to the Alkylation units (Units 433 and 869);

- Naphtha – Marcus Hook provided about 7 to 12 MBPD of naphtha as incremental feed to the Reformer units (Units 860 and 1332) to make hydrogen and reformate. The volume depended on crude mix/naphtha content.

- Light Cycle Oil (LCO) – Marcus Hook provided about 10 MBPD of LCO as feed to Hydrodesulfurization units (Units 231, 866, and 859) to make ultra-low sulfur diesel.

- Benzene – Marcus Hook sent all of its benzene production (approximately 3 to 4 MBPD) as feed to the Cumene unit to make cumene.

On a less frequent basis, Marcus Hook would also send untreated cat gasoline to the Philadelphia Refinery for processing through the Low Sulfur Gasoline unit to reduce the sulfur content.

2.4 *SCHEDULE*

PES seeks to implement this plan approval as soon as possible. Since this plan approval involves no physical modifications to five of the target heaters at the Refinery, PES intends to implement those firing rate increases immediately upon plan approval issuance. For the Unit 231-B101 Heater and Unit 865-11H1 Heater, PES will not implement the firing rate increases until the ultra-low NO_x burners have been installed (per the CAC settlement PES plans to install the burners within 18 months of plan approval issuance).

Figure 2-1 Girard Point Processing Area Process Flow Diagram

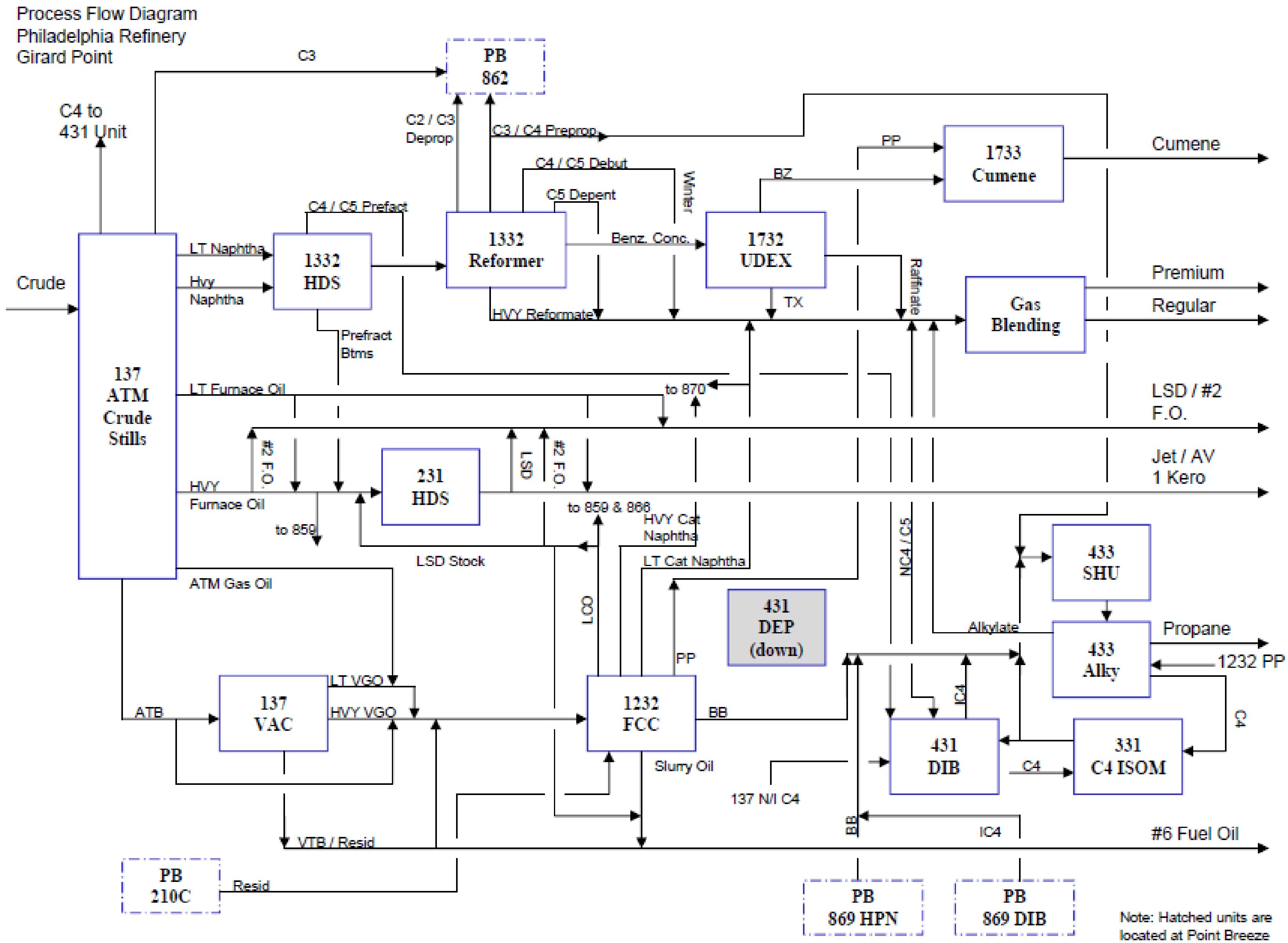
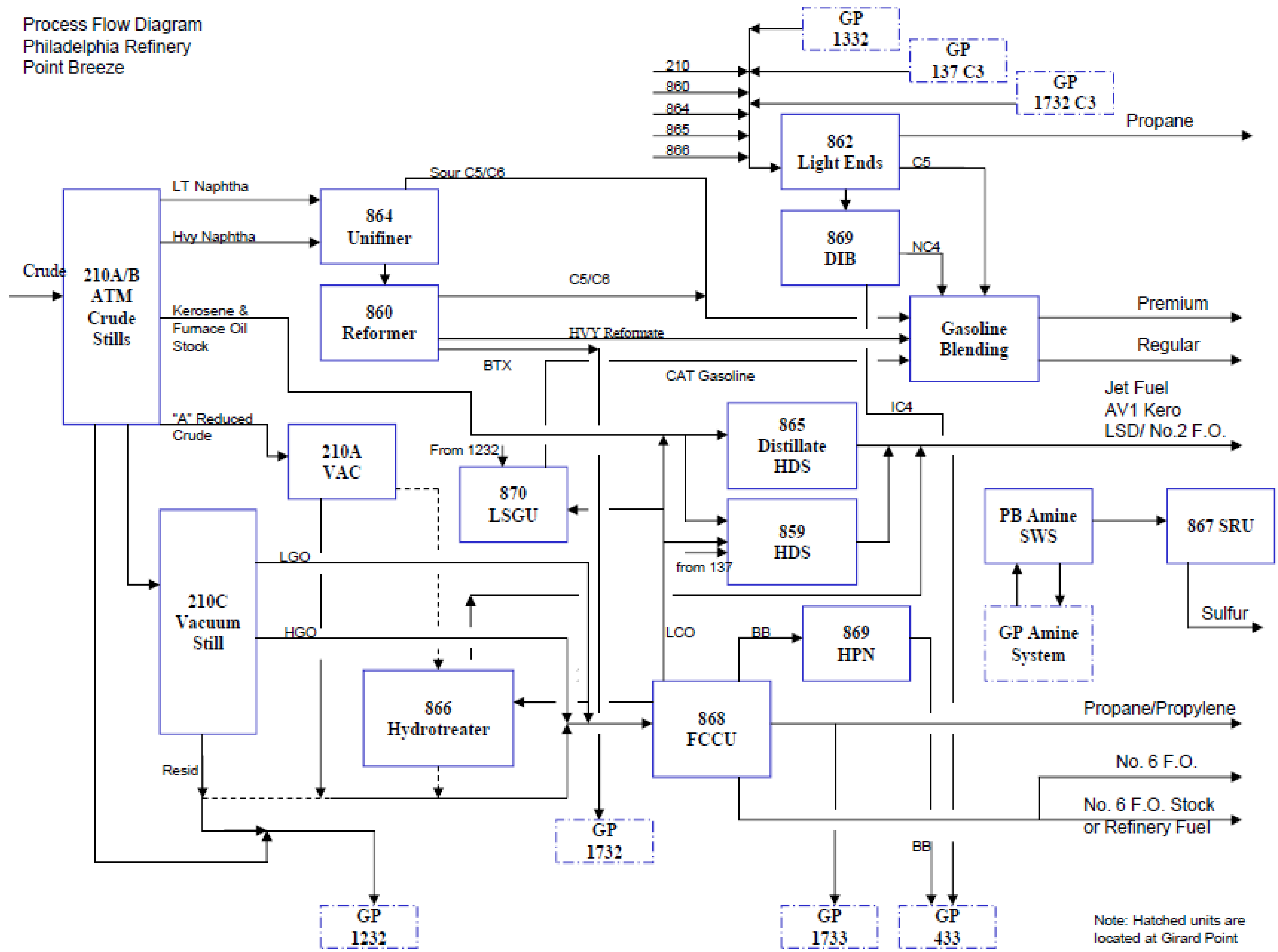


Figure 2-2 Point Breeze Processing Area Process Flow Diagram



3.0 *PLAN APPROVAL EMISSIONS*

In this plan approval application, the emissions from the target heaters and upstream/downstream ancillary units were calculated using the methodology described below.

Because this project will not require any changes beyond the installation of ULNBs to the target heaters or any other upstream/downstream ancillary units at the Refinery, the emissions changes associated with the target heaters are attributed to the incremental changes in firing rates from historic operation during a defined baseline period to rates projected for the future. Similarly, the emissions increases associated with the ancillary units are attributed to potential incremental increase in crude throughput in the future as compared to the baseline period. As referenced earlier, the baseline period is January 2010 through December 2011.

The emissions changes from both the target heaters and ancillary units are calculated through a step-wise process. Initially, the emissions changes are calculated as the difference between the baseline actual emissions (BAE) and the future projected actual emissions (PAE). As per 25 Pa Code §127.203a(a)(4)(i) and 40 CFR §52.21(b)(48), BAE were estimated as the highest annual average "during a consecutive 24-month period selected by the owner or the operator within the 5-year period immediately prior to the date a complete plan approval application is received by the Department". Similarly, the projected actual emissions were estimated as the maximum emissions that the plan approval sources are projected to emit "in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project".

In addition, as per 25 Pa Code §127.203a(5)(i)(C), 40 CFR 52.21(b)(41)(c), and EPA guidance, the Refinery calculated and excluded any increase in emissions from sources affected by this plan approval that could have been accommodated in the 24-month period representing the baseline period, and that are unrelated to the plan approval[5].

Table 3-5 shown at the end of this section shows the Total Heater Firing Rate Increase Plan Approval emission increases. Detailed emissions

[5] USEPA, 2010. Letter from Gregg M. Worley, Chief- Air Permits Section, USEPA Region IV to Mark Robinson, Georgia Pacific Wood Products LLC, re: PSD Emissions Calculation and Demand Growth; 18 March 2010. EPA concurred with Georgia Pacific that the "highest demonstrated average monthly operating level during the baseline period" could be used as an approximation for the level the unit could have accommodated during the baseline period.

calculations for all target heaters and upstream/downstream ancillary units can be found in Attachment D.

3.1 TARGET HEATERS

To calculate the annual emissions (tons per year) from the target heaters, the future annual firing duty must be established. All pollutant emission changes refer to the future projected annual firing rate as compared to the past actual annual firing rate calculated from the actual firing in 2010 and 2011.

Note that the projected annual firing rate (MMBtu/year, annual average) for the heaters is projected to be lower than the projected maximum annual firing based on design capacity, that is, the design MMBtu/hr rate, which is the basis for the RACT analysis in Attachment A. This approach to setting the basis for the annual firing rates reflects the reality of refining operations where operations can vary seasonally and in response to market demand and other factors. In fact, all heaters at the Refinery operate at annual average firing rates lower than their maximum design firing rate.

The annual emission changes in this plan approval application reflect the difference between past actual emissions and future projected actual emissions based on maximum expected annual firing duty.

The sections below discuss the methodology for calculating the target heater emissions for this plan approval for each pollutant. Table 3-1 below shows the future projected actual emissions for each target heater. Consistent with AMS practice of establishing annual emission limits corresponding to PAE values, Section 7 contains proposed permit conditions including annual emission limits (TPY) for the target heaters.

3.1.1 Primary Pollutants VOC, PM/PM_{10}/$PM_{2.5}$, CO, and Lead

Consistent with historic practices, the Refinery used EPA AP-42 emission factors for volatile organic compounds (VOC), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), carbon monoxide (CO), and lead for the target heaters. The EPA AP-42 factors are expressed as pounds per million standard cubic feet (lb/MMscf) of natural gas burned as fuel. Based on refinery fuel gas testing data, the Refinery calculated the EPA AP-42 emission factor as pounds per million Btu by dividing the EPA AP-42 lb/MMscf factor by the current higher heating value for refinery fuel gas for each heater. The future projected emissions are calculated using the future projected annual firing duty and the EPA AP-42 emission factors.

3.1.2 *Primary Pollutant SO_2*

This plan approval will allow for an increase in firing of certain target heaters; however, it is not expected to have an impact on the amount of sulfur in the refinery fuel gas, which is the only fuel for refinery heaters. Sulfur dioxide (SO_2) emissions have historically been estimated based on daily averages of the sulfur content in fuel gas; however, the target heaters only became subject to refinery fuel gas sulfur limits required by New Source Performance Standards Subpart J for Petroleum Refineries in 2011. Therefore, for this plan approval, the 2011 actual SO_2 emissions and 2011 actual fired rates for the each target heater were used to derive a heater-specific SO_2 emission factor. The 2011 actual SO_2 emissions rate (lb/MMBtu) varies for each heater because it is calculated as the daily weighted average based on heater firing (MMBtu/hr). The future projected SO_2 emissions were calculated using the future projected annual firing duty and the heater-specific SO_2 emission factor.

3.1.3 *Primary Pollutant CO_2e*

The Philadelphia Refinery annually reports greenhouse gas (GHG) emissions in the units of carbon dioxide equivalents (CO_2e) to the EPA as required by the Mandatory Greenhouse Gas Reporting rule codified at 40 CFR Part 98. The GHG emission factors used for this plan approval were derived following the methods described in 40 CFR 98 Subpart C for General Stationary Fuel Combustion Sources, which includes an analysis of the composition of the refinery fuel gas being combusted for each heater. The GHG emission factor for each heater was derived from the emission factors in Subpart C and the higher heating value of the refinery fuel gas being used. The future projected CO_2e emissions for this plan approval were calculated using the future projected annual firing duty of each heater and the heater-specific CO_2e emission factor. This method is at least as accurate as the EPA AP-42 emission factor for CO_2 as this factor only reflects the combustion of natural gas.

3.1.4 *Primary Pollutant NO_x*

The methodology used to select the NO_x emission factors for the target heaters is described below. As seen below, because some of the heaters already have RACT permit limits, the Refinery used the NO_x emission factors used to derive those limits for those heaters as opposed to EPA AP-42 emission factors used in the annual emissions reports to AMS. The Refinery proposes to amend reported Emission Inventories submitted to

AMS for 2010 and 2011, for heaters where the annual emissions used in this analysis are different from the emissions reported earlier. The NO_x emission factor used for each heater is discussed below:

- For the Unit 231-B101 Heater, the BAE shown in reported Emission Inventories are adjusted to recognize that this heater has an expected NO_x emission factor of 0.122 lb/MMBtu. Future projected NO_x emissions for this heater for this plan approval are based on expected NO_x emission factor 0.03 lb/MMBtu based on the expected installation of ultra-low NO_x burners and the future projected annual firing duty.

- For the Unit 865-11H1 Heater, the BAE was based on the RACT NO_x limit of 0.113 lb/MMBtu, which is lower than the EPA AP-42 emission factor used in the reported Emission Inventories, as the baseline emissions could not be greater than an applicable emissions limit. Future projected NO_x emissions for this heater for this plan approval are based on the expected NO_x emission factor 0.03 lb/MMBtu based on the expected installation of ultra-low NO_x burners and the future projected annual firing duty.

- For the Unit 865-11H2 Heater, the use of EPA AP-42 emission factor was specified by AMS for use in the reported Emission Inventories. To be conservative, the Refinery used the same current RACT NO_x limit for the Unit 865 11H1, which is greater than the EPA AP-42 emission factor, to calculate the BAE for the plan approval. The Refinery proposes to amend the reported Emission Inventories to reflect the higher emission factor of 0.113 lb/MMBtu for this heater. Future projected NO_x emissions for this heater for this plan approval are based on the RACT emission rate and the future projected annual firing duty.

- For the Unit 210-H101 Heater, the BAE was based on the RACT NO_x limit of 0.089 lb/MMBtu, which is lower than the EPA AP-42 emission factor used in the reported Emission Inventories, as the baseline emissions could not be greater than an applicable emissions limit. Future projected NO_x emissions for this heater for this plan approval are based on the RACT emission rate and the future projected annual firing duty.

- For the Unit 210-H201 Heater, the BAE was based on the average of actual CEMS data for the years 2010 and 2011. The future projected NO_x emission rate is based on the permit limit for the heater of 0.03 lb/MMBtu. Future projected NO_x emissions for this heater for this plan approval are based on the NO_x permit limit and the future projected annual firing duty.

- For the Unit 866-12H1 and Unit 868-8H101 Heaters, the BAE and the future projected emissions were established using the same approach as that used for the Unit 865-11H2 Heater.

Table 3-1 Future Projected Actual Emissions Increases from Target Heaters

Target Heater	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	CO (TPY)	VOC (TPY)	NO_x (TPY)	SO_2 (TPY)	Lead (TPY)	CO_2e (TPY)
Unit 231-B101	1.4	1.4	1.4	15.9	1.0	0.0	0.4	9.5E-05	22,738
Unit 865-11H1	0.7	0.7	0.7	7.7	0.5	0.0	0.2	4.6E-05	10,978
Unit 865-11H2	0.6	0.6	0.6	6.3	0.4	8.7	0.2	3.8E-05	9,038
Unit 210-H101	0.9	0.9	0.9	10.0	0.7	11.0	0.5	5.9E-05	14,301
Unit 210-H201	2.1	2.1	2.1	23.2	1.5	12.5	0.8	1.4E-04	33,284
Unit 866-12H1	1.1	1.1	1.1	12.0	0.8	16.6	0.3	7.1E-05	17,156
Unit 868-8H101	0.3	0.3	0.3	3.4	0.2	4.9	0.1	2.0E-05	4,924
Total Target Heater Emission Increases[1]	**7.1**	**7.1**	**7.1**	**78.5**	**5.1**	**53.8**	**2.5**	**4.7E-04**	**112,420**

[1] The Refinery calculated the emissions from the target heaters that they were capable of accommodating in the 24-month baseline period and these are accounted for (subtracted from) future projected actual emissions shown in this table. See the Emissions Calculations in Attachment D for details.

3.2 *UPSTREAM/DOWNSTREAM ANCILLARY UNITS*

The increase in the firing rate limits sought for the target heaters is expected to increase utilization of upstream/downstream ancillary units on an annualized basis as compared to that achieved in the baseline period. PES has estimated the future potential incremental increase in crude throughput at the Philadelphia Refinery that is expected as a result of this plan approval. Following this project, PES conservatively estimated a level of crude processing of 346 MBPD. The average actual crude throughput during the 24-month baseline period was 284.4 MBPD, where the highest monthly throughput occurred in June 2010 at 316.5 MBPD. It is noted though that, while the use of crude processing rate provides a means to project emissions from ancillary units, it is a conservative approach and does not capture the potential impacts of changes in crude slate. Most notably, the refinery has achieved a monthly average throughput of 342.7 MBPD in June 2013, while still remaining in compliance with the existing, lower firing rate limits for the seven heaters.

The potential incremental increases in emissions from upstream/downstream ancillary units have been estimated by scaling the potential incremental increase in crude throughput as compared to past actual crude throughput rates during the baseline period at the Refinery.

The sections below describe the emissions calculations for each type of upstream/downstream ancillary unit affected by this plan approval.

3.2.1 *Ancillary Process Heaters and Boilers*

Future emissions from the ancillary process heaters and boilers are calculated by scaling historical emissions from the ancillary units with the maximum expected crude increase, which is approximately 22%. All boilers at the No. 3 Boilerhouse are expected to increase utilization as a result of this plan approval, as are all of the ancillary heaters listed in Table 3-2 below.

Table 3-2 Ancillary Process Heaters

Ancillary Process Heaters	
Unit 137 F-1 Heater	Unit 860 2H4 Heater
Unit 137 F-2 Heater	Unit 860 2H5 Heater
Unit 137 F-3 Heater	Unit 860 2H7 Heater
Unit 210 13H-1 Heater	Unit 860 2H8 Heater
Unit 1332 H-400 Heater	Unit 864 PH1 Heater
Unit 1332 H-401 Heater	Unit 864 PH7 Heater
Unit 1332 H-601 Heater	Unit 864 PH11 Heater
Unit 1332 H-602 Heater	Unit 864 PH12 Heater
Unit 1332 H-1 Heater	Unit 859 1H1 Heater
Unit 1332 H-2 Heater	Unit 870 H-01 Heater
Unit 1332 H-3 Heater	Unit 433 H-1 Heater
Unit 860 2H2 Heater	Unit 1232 B-104 Heater
Unit 860 2H3 Heater	Unit 870 H-02 Heater

As discussed in Section 3.0 for the target heaters, the Refinery also excluded emissions increases that the ancillary process heaters and boilers were capable of accommodating in the baseline period and that are thus unrelated to the plan approval. Table 3-3 below shows the future projected actual emissions for the ancillary process heaters and boilers.

Table 3-3 Future Projected Actual Emissions from Ancillary Process Heaters and Boilers

Pollutant	Ancillary Process Heater and Boiler Emissions (TPY)
PM	6.1
PM_{10}	6.1
$PM_{2.5}$	6.1
CO	94.2
VOC	6.3
NO_x	82.1
SO_2	3.2
Lead	6.1E-04
CO_2e	138,640

3.2.2 Upstream/Downstream Ancillary Units (excluding Heaters and Boilers)

The emissions increases associated with other upstream/downstream ancillary units, except heaters and boilers, were calculated based on a projected increase in crude throughput over the baseline 24-month period. Similar to the ancillary process heaters and boilers, the emissions from other ancillary units were calculated by scaling the potential incremental increase in crude throughput as compared to past actual crude throughput rates during the baseline period at the Refinery. Ancillary units include:

- Point Breeze, Girard Point, and Schuylkill River Tank Farm Wastewater Treatment Plants;
- Girard Point and Point Breeze marine vessel loading;
- Girard Point butane/polypropylene truck loading; and
- Sulfur recovery units.

As discussed in Section 3.0 for the target heaters, the Refinery also excluded emissions increases that the upstream/downstream ancillary units were capable of accommodating in the baseline period and which are unrelated to the plan approval. Table 3-4 below shows the future projected actual emissions for the upstream/downstream ancillary units.

Table 3-4 Future Projected Actual Emissions from Upstream/Downstream Ancillary Units

Pollutant	Upstream/Downstream Ancillary Units Emissions (TPY)
PM	0.03
PM_{10}	0.03
$PM_{2.5}$	0.03
CO	18.9
VOC	11.7
NO_x	4.2
SO_2	1.3
Lead	0.0
CO_2e	4,312

3.2.3 *Unmodified Storage Tanks*

Typical light hydrocarbon (gasoline) tanks emit 96% of their VOC emissions from breathing losses and only 4% from working losses. However, only the working losses are affected by throughput. Therefore, only the VOC working losses from unmodified storage tanks associated with this plan approval were scaled by the potential incremental increase in overall Refinery crude throughput over the baseline - approximately 22% (0.96 + 0.04 x 1.22 = 1.009).

Note that no credits (emission reductions) are being taken for the cessation of processing Marcus Hook intermediates at the Refinery.

The future projected actual emissions for the unmodified storage tanks are included in the VOC emissions in Table 3-4 above.

3.2.4 *Unaffected Upstream/Downstream Ancillary Units*

The remaining sources at the Refinery are unaffected. That is, it is not appropriate to scale these sources' emissions based on expected changes in facility crude throughput because the emissions from these units are not rate dependent.

Specifically, such unaffected upstream and downstream ancillary units include:

- Leak Detection and Repair emissions;

- Cooling tower emissions;
- Flare emissions;
- Sampling system emissions; and
- Reciprocating internal combustion engine emissions.

3.3 TOTAL PLAN APPROVAL EMISSION CHANGES

The total future projected actual emission increases from the Heater Firing Rate Increase Plan Approval are summarized in Table 3-5.

Table 3-5 Total Heater Firing Rate Increase Plan Approval Emission Increases

Source	Pollutant (TPY)									
	NO_x	SO_2	CO	VOC	PM	$PM_{10}/PM_{2.5}$	Sulfuric acid mist	Lead	HAP	CO_2e
Target Heater Emissions	53.8	2.5	78.5	5.1	7.1	7.1	0	4.7E-04	0	112,420
Ancillary Process Heaters and Boilers	82.1	3.2	94.2	6.3	6.1	6.1	0	6.1E-04	0	138,640
Upstream/Downstream Ancillary Units	4.2	1.3	18.9	11.7	0.03	0.03	0	0	0	4,312
Total Plan Approval Emissions	**140.1**	**7.1**	**191.6**	**23.2**	**13.2**	**13.2**	**0.0**	**1.1E-03**	**0.0**	**255,372**

4.0 *REGULATORY OVERVIEW*

PES must comply with all federal and state requirements applicable to this proposed plan approval. The existing units are subject to standards covered under the NSPS, MACT and state program requirements and will continue to be after the proposed plan approval. The existing facility is a major stationary source of emissions for all criteria pollutants and greenhouse gases; therefore, the plan approval is required to undergo a New Source Review (NSR) analysis. The Philadelphia Refinery is located in an area designated as moderate nonattainment for ozone; however, for NSR analysis, the area is treated as a severe nonattainment area. Additionally, Philadelphia County is designated a $PM_{2.5}$ nonattainment area. It is designated as attainment for other criteria pollutants.

PES must evaluate the plan approval for applicability of the nonattainment NSR program for VOC, NO_x, and $PM_{2.5}$ emissions, and applicability of the Prevention of Significant Deterioration (PSD) program for NO_2, SO_2, CO, PM, PM_{10}, lead, and sulfuric acid mist (SAM). In addition, PES is required to determine if GHG pollutants would be regulated as a part of the plan approval. The following sections provide the detailed regulatory analysis for the plan approval.

4.1 *PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS*

The PSD regulations (40 CFR 52.21) are federal regulations that apply to new major sources and "major modifications" of existing "major stationary sources" located in attainment or unclassifiable areas for a given pollutant. The PSD regulations are enforced by PADEP in accordance with 25 Pa Code §127.81. The Philadelphia Refinery is a major stationary source, and a modification to the source that would result in a "significant emission increase" and a "significant net emissions increase" would trigger PSD applicability.

The PSD regulations define a major modification in 40 CFR 52.21(b)(3)(i) as any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase and a significant net emission increase of any pollutant subject to regulation under the Act. The regulation defines threshold levels of annual emission rates that constitute "significant increases" for a variety of pollutants. The PSD emissions analysis is performed as per applicable regulation in 25 Pa

Code §127.81 and 40 CFR §52.21. EPA takes the position that the PSD emissions analysis should be performed in two steps[6].

4.1.1 *Plan Approval Emissions Analysis (Step 1)*

In Step 1 of the analysis, the emissions increases from all plan approval sources including the target heaters whose rates are increased and the ancillary units are calculated. The emissions calculation methodology was described in the earlier sections. As indicated in the Table 4-1 below, NO_2, CO, and CO_2e emissions for the proposed plan approval exceed the PSD threshold; therefore, PES performed a netting analysis over the contemporaneous period for these three pollutants.

Table 4-1 PSD Emissions Analysis (Step 1)

Emissions	Pollutant (TPY)							
	NO_2	**SO_2**	**CO**	**PM**	**PM_{10}**	**Sulfuric acid mist**	**Lead**	**CO_2e**
Heater Firing Rate Increase Plan Approval	140.1	7.1	191.6	13.2	13.2	0.0	1.1E-03	255,372
PSD Significant Level	40	40	100	25	15	7	0.6	75,000
PSD Triggered (Before Netting Analysis)	**Yes**	**No**	**Yes**	**No**	**No**	**No**	**No**	**Yes**

The PSD netting analyses for NO_2, CO, and CO_2e are discussed in Section 4.1.2. The PSD netting analysis includes other contemporaneous emission increases and decreases at the facility in the past five years.

4.1.2 *PSD Emissions Netting Analysis (Step 2)*

If the emissions from a plan approval exceed the applicable significant emission rate for a PSD regulated pollutant, the facility can choose to net out the emissions increase from the plan approval with other reductions in emissions that have occurred during the contemporaneous emissions period. PSD regulations allow the use of a netting analysis to determine if a "significant net emission increase" will occur as a result of a plan approval. PES has performed the netting analysis consistent with PSD

6 EPA, 2010. Re: Hovensa Gas Turbine Nitrogen Oxides Prevention of Significant Deterioration (PSD) Permit Application – Emission Calculation Clarification; Letter from Stephen Riva, Permitting Chief to Kathleen Antoine, Environmental Director, Hovensa, LLC. March 30, 2010. While PES does not agree that this two-step analysis is compelled by the PSD regulations or the Clean Air Act, PES follows it here.

regulations in 40 CFR §52.21. A six-step procedure is used for determining the net emissions change and is summarized below.

1. Emission Increases from the Proposed Plan Approval - Determine the emission increases from the proposed plan approval. If increases are significant, proceed; if not, the plan approval is not subject to PSD review.
2. Contemporaneous Period - Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed plan approval.
3. Emissions Increases and Decreases during the Contemporaneous Period - Determine which emissions units at the facility experienced (or will experience, including any proposed decreases resulting from the proposed plan approval) a creditable increase or decrease in emissions during the contemporaneous period.
4. Creditable Emissions Changes - Determine which contemporaneous emissions changes are creditable.
5. Amount of the Emissions Increase and Decrease - Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.
6. PSD Review - Sum all contemporaneous and creditable increases and decreases with the emissions changes from the proposed plan approval to determine if a significant net emissions increase will occur.

In order to perform a netting analysis, the contemporaneous periods must be determined. The term "contemporaneous period" is defined in the PSD regulations as the period that includes the five (5) years prior to initiating construction on a proposed modification, and the period between the initiation of construction and the initiation of operation of the new or altered equipment. Because this plan approval involves no physical change to any units at the Refinery, the initiation of operation of the Heater Firing Rate Increase Plan Approval will occur immediately upon approval. Therefore, the contemporaneous period for this plan approval runs from 2nd Quarter 2008 through the 3rd Quarter 2013.

Table 4-2 below summarizes the contemporaneous and creditable emissions increases/decreases included in the plan approval PSD netting analysis. Detailed emissions estimates and netting analyses are provided in Attachment D.

Table 4-2 PSD Contemporaneous Netting Analysis (Step 2)

Emissions	NO_2 Emissions (TPY)	CO Emissions (TPY)	CO_2e Emissions (TPY)
Heater Firing Rate Increase Plan Approval	140.1	191.6	255,372
Contemporaneous Increases/Decreases	-320.7	-17.5	-310,956
Total	**-180.7**	**174.1**	**-55,583**
PSD Significance Level	40	100	75,000
PSD Review Required	**No**	**Yes**	**No**

As shown in Table 4-2, the Heater Firing Rate Increase Plan Approval triggers PSD review for CO. Therefore, a full PSD review is required for CO as a result of this plan approval. The PSD review requirement for CO is summarized below:

- Apply Best Available Control Technology (BACT) for regulated pollutants emitted above PSD thresholds for all applicable emissions units (see discussion in Section 5 of this report); and

- Assess the ambient impact of emissions through the use of dispersion modeling (Attachment F).

Also shown in Table 4-2, the Heater Firing Rate Increase Plan Approval does not exceed the PSD significance level for NO_2; therefore, further PSD review is not required. In addition, the emissions of GHG are less than the applicable threshold; therefore, GHG is not considered a regulated pollutant in this plan approval.

4.2 NON-ATTAINMENT NEW SOURCE REVIEW ANALYSIS

Major sources located in nonattainment areas must evaluate whether a change constitutes a major modification under nonattainment NSR regulations (NA-NSR). The requirements are defined in 25 Pa Code §127.201 through §127.217. For this plan approval, PES evaluated NA-NSR under the revised NSR requirements published in the *Pennsylvania Bulletin* on May 19, 2007. Currently, Philadelphia is designated as a moderate nonattainment area for ozone and nonattainment for $PM_{2.5}$.

Under the revised Pennsylvania NSR regulation, facilities located in the five-county area (including Philadelphia County) are subject to NSR requirements for serious or severe ozone classification. The applicability threshold under the special permit requirements codified at §127.203(b) for serious or severe classification is 25 TPY for both VOC and NO_x emissions. When considering a modification, major sources must determine if either of the following conditions exceed the 25 TPY threshold for VOC or NO_x, which would subject the facility to special permit requirements:

- Increases or decreases in emissions from the plan approval are aggregated with other net emissions increases over the consecutive 5-calendar year period including the year in which the plan approval is constructed (calendar years 2009 – 2013 for this Plan Approval); and

- Increases or decreases in emissions from the plan approval are aggregated with other net emission increases or decreases over the previous 10-year period. If the result is over threshold levels, the facility is subject only to the emissions offset requirements codified at 25 Pa Code §127.205.

If the resulting net change exceeds the applicable thresholds, those emissions must be offset by a ratio of 1.3 to 1. If the offsets come from internal emission reductions, then Lowest Achievable Emission Rate (LAER) requirement does not apply (25 Pa Code §127.203(b)(3)).

Table 4-3 below presents a summary of plan approval emissions for VOC and NO_x aggregated with other net emissions increases over the consecutive 5-calendar year period including the year in which the plan approval implementation is planned (calendar years 2009 through 2013).

Table 4-3 NA-NSR Netting Analysis for VOC and NO_x Emissions (5-year)

Plan Approval	5-year NO_x (TPY)	5-year VOC (TPY)
Heater Firing Rate Increase Plan Approval	140.1	23.2
Contemporaneous Increases	10.7	2.8
Net Emissions Increase	**150.7**	**26.0**
Internal Offsets required (1.3:1 Ratio)	195.9	33.8
Netting Credits Applied[1]	-195.9	-33.8
Net Emissions (After Offsetting, if applicable)	**0.0**	**0.0**
NA-NSR Significance Level	**25**	**25**
NA-NSR Review Required	**No**	**No**

[1] The 5-calendar year net emission increase for NO_x and VOC is offset using internal netting credits at a ratio of 1.3:1 as required by 25 Pa Code §127.203(b)(3).

Table 4-4 below presents a summary of plan approval emissions for NO_x and VOC aggregated with other net emission increases or decreases over the previous 10-year period.

Table 4-4 NA-NSR Netting Analysis for VOC and NO_x Emissions (10-year)

Plan Approval	10-year NO_x (TPY)	10-year VOC (TPY)
Heater Firing Rate Increase Plan Approval	140.1	23.2
Contemporaneous Increases/Decreases	-296.7	-11.4
Net Emissions Increase	**-156.7**	**11.7**
NA-NSR Significance Level	**25**	**25**
NA-NSR Review Required	**No**	**No**

As shown in Tables 4-3 and 4-4 above, the net emissions increases of VOC and NO_x from the proposed plan approval are below the NA-NSR applicability thresholds of 25 tons per year. Therefore, the proposed plan approval is not subject to NA-NSR requirements for ozone.

For $PM_{2.5}$, NA-NSR will be triggered if changes in direct $PM_{2.5}$ emissions exceed 10 TPY or emission changes associated with precursors such as NO_x or SO_2 exceed 40 TPY. As indicated in Table 4-5 below, NO_x emissions for the proposed plan approval exceed the NA-NSR regulatory threshold as a precursor to $PM_{2.5}$; therefore, as per 25 Pa Code §127.203a(a)(1)(i)(A), a netting analysis over the contemporaneous period must be performed.

Table 4-5 NA-NSR Analysis for SO_2, NO_x, and $PM_{2.5}$ Emissions (Step 1)

Plan Approval	SO_2 (TPY)	NO_x (TPY)	$PM_{2.5}$ (TPY)
Heater Firing Rate Increase Plan Approval	7.1	140.1	13.2
NA-NSR Significance Level	**40**	**40**	**10**
NA-NSR Triggered (Before Netting Analysis)	**No**	**Yes**	**Yes**

As shown in Table 4-6 below, the $PM_{2.5}$ and NO_x (as a $PM_{2.5}$ precursor) netting analysis over the contemporaneous period shows that the emissions from the plan approval are not greater than the NA-NSR thresholds for $PM_{2.5}$. Therefore, the proposed plan approval is not subject to 25 Pa Code §127.203a for $PM_{2.5}$.

Table 4-6 NA-NSR Netting Analysis for $PM_{2.5}$ and NO_x as $PM_{2.5}$ Precursor (Step 2)

Plan Approval	NO_x (TPY)	$PM_{2.5}$ (TPY)
Heater Firing Rate Increase Plan Approval	140.1	13.2
Contemporaneous Increases/Decreases	-320.7	-22.3
Net Emissions Increase	**-180.7**	**-9.0**
NA-NSR Significance Level	**40**	**10**
NA-NSR Review Required	**No**	**No**

5.0 BACT ANALYSIS FOR CO CONTROL

As shown in Section 4.1.2, the net increase in CO emissions associated with this plan approval is above the PSD threshold. Therefore, the target heaters are subject to the application of BACT.

5.1 METHODOLOGY

BACT is defined in 40 CFR 52.21(b)(12) of the PSD regulations as "...an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any…source…which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs". Both 25 Pa Code §127.83 and AMS Regulation I, Section XI, Part C incorporate the PSD regulations codified in 40 CFR 52.21 by reference.

Each BACT analysis is done on a case-by-case basis, where the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of the expected reduced emissions which the technology would bring. In no event however, can an emission limitation be recommended that would not be at least as stringent as any applicable standard of performance under 40 CFR Parts 60 (New Source Performance Standards) and 61 ((National Emission Standards for Hazardous Air Pollutants). Additionally, if the reviewing authority finds during the course of a BACT analysis that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant.

In summary, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent or "top" alternative. This alternative is to be selected as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Under the "top-down" approach, as described in EPA's *Draft New Source Review Workshop Manual*, the five basic steps of a "top-down" BACT analysis are listed as follows:

Step 1: Identify potential control technologies

Step 2: Eliminate technically infeasible options

Step 3: Rank remaining control technologies by control effectiveness

Step 4: Evaluate the most effective controls and document results

Step 5: Select BACT

The first step is to identify potentially "available" control options for each emission unit triggering PSD, for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. The list includes technologies used to satisfy BACT requirements, innovative technologies, and controls applied to similar source categories.

During any BACT review, typically, the following sources are investigated to identify potentially available control technologies:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database;
- EPA's New Source Review Website;
- In-house experts;
- State air regulatory agency contacts;
- Technical articles and publications;
- State permits issued for similar sources that have not yet been entered into the RBLC; and
- Guidance documents and personal communications with federal and state agencies.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important, in this step, that the technical basis for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source-specific factors related to safe and successful use of the controls.

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation. Potential adverse impacts of implementing such technology, however, must still be identified and evaluated.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. The economic or "cost-effectiveness" analysis is conducted in a manner consistent with EPA's *OAQPS Control Cost Manual* Fifth Edition (EPA 1996) and subsequent revisions. An important aspect of the top-down BACT methodology is the establishment of baseline emission levels that are used in calculating the cost-effectiveness of alternative control options. EPA's Draft *New Source Review Workshop Manual* states that baseline emissions should be a realistic upper bound estimate of emissions taking into account physical or operational constraints and historical operating data.

The fifth and final step is to select as BACT the emission limit resulting from application of the most effective of the remaining technologies under consideration for each pollutant of concern.

5.2 IDENTIFY ALL CONTROL TECHNOLOGIES

This plan approval will require the target heaters to be evaluated for CO controls. The potentially available emission controls for reducing CO emissions from heaters are:

- Good combustion practices; and
- Oxidation catalysts.

Based on a review of EPA's RBLC database, Bay Area Air Quality Management District (BAAQMD) BACT database (see Attachment G), and other permits issued for refineries, no documented cases of oxidation catalysts being implemented on similarly sized heaters were identified. Therefore, installation of oxidation catalyst for heaters of this size has not been demonstrated and is not available. The lack of application in refineries is largely due to operational limitations of the oxidation catalysts. The installation of oxidation catalyst in flue gas containing more than trace levels of SO_2 will result in poisoning and deactivation of the catalyst by sulfur-containing compounds, as well as increasing the conversion of SO_2 to SO_3. This would increase condensable particulate matter emissions, which would foul the catalyst, in turn, prohibiting oxidation as well as increasing flue gas system corrosion rates. Another operating limitation is that oxidation catalysts typically operate at 650 degrees Fahrenheit (°F) to 1,000°F to be effective at minimizing CO emissions. None of the heaters in this BACT analysis achieve stack temperatures within the typical operating range of an oxidation catalyst.

5.3 ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

This step of the top-down BACT analysis eliminates from consideration technically infeasible options. A control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that include safe and successful operation of a control option at a specific location.

While documented application of oxidation catalysts for refinery heaters similar to those in this plan approval application has not been identified and operational limitations related to stack temperatures and catalyst poisoning prevent the use of oxidation catalysts on the existing target heaters – making the technology infeasible, PES will nonetheless carry that technology forward to the next steps. Thus, all options presented will be explored in more detail.

5.4 RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

The next step in the top-down BACT analysis is to rank the remaining control technologies by control effectiveness. Technologies for minimizing CO emissions from the target heaters (estimated level of reduction):

1. Good combustion practices (reduction level varies based on heater configurations)

2. Oxidation catalysts (50-92%[7])

5.5 *EVALUATE MOST EFFECTIVE CONTROLS BASED ON ECONOMIC, ENERGY, AND ENVIRONMENTAL IMPACTS*

The fourth step in the top-down BACT analysis involved the evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

While the use of an oxidation catalyst has not been identified as a demonstrated technology for refinery heaters, the Refinery has estimated the cost effectiveness at approximately $10,800 to $17,800 per ton of CO emissions reductions (see analysis presented in Attachment H). An EPA guidance document was used as the basis for this analysis and limitations regarding stack temperatures relative to required catalyst operating temperatures as well as any impacts of catalyst fouling were ignored. The EPA Air Pollution Control Technology Fact Sheet for Regenerative Incinerator (EPA-452/F-03-021) shows that capital costs range from $51.50 to $206 per cubic foot per minute (cfm) and operation and maintenance costs range from $8.80 to $29.40 per cfm (costs escalated from 2002 to 2012 dollars). Conservatively, PES estimated cost effectiveness using $51.50 per cfm for capital costs and $8.80 per cfm for operation and maintenance costs. Further note - as PES is a recently established company in a private equity structure, the cost of borrowing capital (the minimum return that investors expect for providing capital to the company) is considered at a higher risk than many established companies. The cost effectiveness analysis reflects the current cost of capital for PES, which is 21.83%.

The estimates of potential emission reductions that could be achieved through the application of an oxidation catalyst, and corresponding control effectiveness costs ($/ton), are calculated based on the total CO emissions from the sources. As shown in Attachment H, even when using the most conservative (lowest expected) capital and annual operating and maintenance costs and ignoring potential issues regarding flue gas temperatures, the installation of oxidation catalyst for CO control would not be considered cost effective.

[7] For the BACT cost effectiveness analysis, PES conservatively assumed 92% control effectiveness for application of oxidation catalyst (See Attachment H).

5.6 SELECTION OF BACT

Aside from the technical issues discussed above, the installation of oxidation catalyst for CO control is not considered cost effective and is eliminated from further analysis. Good combustion practice is the predominantly used control option for reducing CO emissions from process heaters. PES currently implements good combustion practice through a comprehensive program of quarterly combustion tuning, as required by the facility's RACT permit. The use of combustion tuning and implementation of periodic maintenance on the heaters ensure that the CO emissions are limited.

Accordingly, good combustion practices are BACT for limiting CO emissions from the heaters.

The heaters will also have annual emission limits (TPY) as discussed in Section 7.

6.0 APPLICABLE STANDARDS

Local, state, and federal regulations, in addition to NA-NSR and PSD have been reviewed for applicability to this plan approval. The following sections provide a summary of these reviews.

6.1 PADEP REGULATIONS - BEST AVAILABLE TECHNOLOGY ANALYSIS

As part of this Plan Approval analysis, AMS has requested a Best Available Technology (BAT) analysis for the applicable target heaters, and PES provides this analysis below.

25 Pa Code §127.12(a)(5) provides that an application for a plan approval must show that emissions from a "new source" will be the minimum attainable through the use of Best Available Technology (BAT). 25 Pa Code §121.1 (Definitions) defines a new source as a source that was constructed and commenced operation on or after July 1, 1972, or a source that was modified so that the fixed capital cost of new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new source[8].

The Unit 231-B101 Heater and the Unit 210-H101 Heater are excluded from this analysis as they were installed prior to July 1, 1972 and have not been modified since that date in any way that would result in the emission of an air contaminant not previously emitted. While Unit 231-B101 Heater was upgraded in 2004 for the installation of low NO_x burners, the cost of those changes was not in excess of the 50% fixed capital cost described above for the project to be considered a "new source" per 25 Pa Code §121.1.

PES has completed a review of available and applicable emission controls beyond those already implemented on these heaters for all criteria pollutants. The target heaters covered by this plan approval and their corresponding construction dates at the Philadelphia Refinery are shown in Table 6-1 below.

[8] The heaters involved in this plan approval are existing sources, not new sources as defined above. Further, the heaters are not being modified as defined above. Therefore, PES believes that BAT analysis is not required as a part of this Plan Approval application. Nonetheless, PES provides this BAT analysis in response to AMS' request for same.

Table 6-1 Target Heaters Construction Dates

Process Unit	Heater	Construction Date
GP Unit 231 HDS	B101 Feed Heater	1957
PB Unit 865 HDS	11H1 Feed Heater	1973
PB Unit 865 HDS	11H2 Reboiler Heater	1973
PB Unit 210 Crude	H101 Crude Heater	1964
PB Unit 210 Crude	H-201A/B Crude Heater	1973
PB Unit 866 HDS	12H1 Feed Heater	1973
PB Unit 868 FCCU	8H101 Recycle Heater	1980

BAT is a pollutant-specific determination. Based on a review of established emission control technologies and emission limits in permits, the following text documents the results of the source and pollutant specific BAT determinations.

The Refinery reviewed publicly available databases to identify potential controls that have been installed on sources similar to the proposed heaters, including:

- EPA's New Source Review website;
- U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database;
- Recent EPA consent decrees within the refining industry; and
- State and federal guidance documents.

Detailed discussion on the BAT analysis for all pollutants affected by this plan approval is presented below.

6.1.1 NO_x Controls

PES reviewed available and applicable NO_x controls that have been installed on process heaters at refineries or similar operations. Currently, combustion tuning is performed on the target heaters to reduce NO_x emissions. In addition, the Unit 210-H201 heater has and Unit 865-11H1 will have ultra-low NO_x burners (ULNB) installed to reduce NO_x emissions as part of this plan approval.

The Refinery evaluated the potential emission reductions that could be achieved beyond the current baseline emissions using more stringent emission controls including:

- Low NO_x Burners (LNB);
- Selective catalytic reduction (SCR);
- Selective non-catalytic reduction (SNCR);
- A combination of ULNB plus SCR; and
- A combination of LNB plus SNCR.

The Refinery estimated the cost effectiveness for additional NO_x controls beyond those currently installed on these heaters in the BAT NO_x cost effectiveness analysis presented in Attachment I. Cost effectiveness of the various technology options range from approximately $7,400 to $41,000 per ton of NO_x emissions reductions. As PES is a recently established company in a private equity structure, the cost of borrowing capital (the minimum return that investors expect for providing capital to the company) is considered at a higher risk than many established companies. The cost effectiveness analysis reflects the current cost of capital for PES, which is 21.83%.

In the cost analyses contained here, costs for NO_x CEMS have not been included in the control effectiveness costs. However, it is expected that installation of a CEMS would likely be requested by AMS as part the installation of any of the control options considered. Adding a CEMS would result in an estimated additional $40,000 in annualized costs, which corresponds to an actual additional cost of $1,400 to $3,900 per ton depending on the NO_x emission rate. Therefore, the control effectiveness costs presented in Attachment I are considered conservative since the actual costs to the Refinery are expected to be greater.

For the Unit 210-H201 and Unit 865-11H1 heaters, PES determined that SCR cannot physically fit the plot plan and there is inadequate pressure from the burners to overcome the SCR pressure drop. Flue gas recirculation would require the installation of mechanical draft burners, a major re-design for both units. Accordingly, ULNBs are considered BAT for the Unit 210-H201 and Unit 865-11H1 heaters.

For the remaining heaters (Unit 865-11H2, Unit 866-12H1, and Unit 868-8H101), the BAT cost effectiveness analysis determined that no additional controls were found to be cost effective, as set forth in

Attachment I. Therefore, operation of the units as proposed under this plan approval and as shown in Table 6-2 below satisfies BAT.

Table 6-2 NO_x BAT Determinations

Process Unit	Heater	Proposed Annual Firing Limit (MMBtu/year)	NO_x BAT
PB Unit 865 HDS	11H1 Feed Heater	699,000	ULNB
PB Unit 865 HDS	11H2 Reboiler Heater	500,000	Tuning [1]
PB Unit 210 Crude	H201 Crude Heater	2,172,000	ULNB
PB Unit 866 HDS	12H1 Feed Heater	456,000	Tuning [1]
PB Unit 868 FCCU	8H101 Recycle Heater	480,000	Tuning [1]

1 Combustion tuning required by the RACT Plan Approval satisfies BAT.

6.1.2 *CO Controls*

See the detailed BACT discussion in Section 5 for CO controls.

Good combustion practices are BAT for limiting CO emissions from the heaters.

6.1.3 *$PM/PM_{10}/PM_{2.5}$ Controls*

The available emission control options for reducing PM emissions from the heaters include:

- Good combustion practices;
- Electrostatic precipitators;
- Baghouse or fabric filters; and
- Use of gaseous fuels.

Refinery fuel gas will be used as the only fuel for these heaters. Based on our review of the RBLC database, BAAQMD, and permits issued at refineries, ESPs or baghouses are not installed on similarly sized heaters fired on refinery fuel gas. Though these control options are potentially technically feasible for combustion sources such as process heaters, they are not commercially demonstrated on similarly sized process heaters.

Therefore, these control options are not further considered in this evaluation. The refinery fuel gas fired in the heaters is comprised of a significant amount of natural gas and therefore, is similar in heating value and characteristics to natural gas.

BAT for limiting PM emissions is good combustion practices and firing of refinery fuel gas.

6.1.4 SO_2 Controls

The available emission control options for minimizing SO_2 emissions from the heaters include:

- Wet flue gas desulfurization (FGD) scrubber;
- Dry FGD scrubber; and
- Use of gaseous fuels.

Based on a review of EPA's RBLC and BAAQMD databases, and permits issued for refineries, wet FGD and dry FGD systems have not been installed on natural gas or refinery fuel gas fired heaters at any refinery in the country. Though these control options are potentially technically feasible for combustion sources such as process heaters, they are not commercially demonstrated on similarly sized process heaters. Therefore, these control options are not considered further in this evaluation.

As described earlier, refinery fuel gas consists of a combination of refinery process by-product gas and natural gas. The refinery by-product gas is desulfurized prior to supplementing with natural gas through a mix drum in order to ensure New Source Performance Standards Subpart J limits are met prior to combustion. Refinery fuel gas is used at every refinery in the country as part of balancing available energy from process operations and by-products.

The use of refinery fuel gas is BAT for the target heaters for SO_2.

6.1.5 VOC Controls

The available emission control options for minimizing VOC emissions from the heaters include:

- Oxidation catalysts; and
- Good combustion practices; and

- Use of gaseous fuels.

Based on our review of the RBLC and BAAQMD databases, oxidation catalysts have not been demonstrated on process heaters at refineries. The predominant control option to reduce VOC emissions from process heaters is the use of good combustion practice. The use of oxidation catalyst is not commercially demonstrated on refinery process heaters. Therefore, oxidation catalysts are not considered further in this analysis.

PES currently implements a comprehensive program of quarterly combustion tuning, as required by the facility's RACT permit. The use of combustion tuning and implementation of periodic maintenance on the heaters ensures that the VOC emissions are limited.

The heaters only fire refinery fuel gas which is lower in VOC content than liquid fuels and some other gaseous fuels. The Refinery removes many VOCs from the by-product gases before they are sent to the refinery fuel gas system and thus refinery fuel gas consists of mostly non-VOC compounds such as methane, ethane, and hydrogen.

The use of good combustion practices and firing of refinery fuel gas is BAT for VOC.

6.2 AIR MANAGEMENT SERVICES REGULATIONS

AMS Regulations incorporate Pennsylvania air contaminant emissions limits and control efficiencies (Regulation I, Section X) and include by reference, the federal regulations (AMS Regulation 1, Section XI). AMS also regulates SO_2 emissions (Regulation III, Section II), fuel sulfur content (Regulation III, Section III), pump and compressor emissions (Regulation V, Section IV), and process equipment leaks (Regulation V, Section XIII).

With regard to Regulation VI, there will be no new air toxic contaminants associated with this plan approval.

There are no AMS regulations that are significantly different from, or more stringent than, the regulations cited herein. The proposed plan approval will not result in any additional AMS applicable requirements.

6.3 FEDERAL REGULATIONS

6.3.1 New Source Performance Standards (NSPS)

The Refinery evaluated whether increasing the firing rates for the target heaters triggers the applicability of NSPS for any Refinery sources. No physical changes or capital expenditures are required to accommodate the increase in firing rates. As such, no sources are considered to be modified sources under EPA's New Source Performance Standards codified under 40 CFR Part 60. Specifically, 40 CFR 60.14(e)(2) excludes from the definition of modification…

> *"an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility."*

The increase in heater firing rates sought in this plan approval represents a production rate increase for the target heaters. All of the heaters serve the same overall purpose - to produce heated hydrocarbon streams for processing. Additionally, as discussed in published EPA guidance, both changes in production rate and operating changes are included in the assessment of capital expenditure associated with the plan approval[9].

The change in firing rates for the target heaters in this plan approval can be achieved without any capital expenditure. Therefore, the target heaters are not considered modified sources and therefore are not subject to NSPS.

While PES is agreeing to voluntarily install ULNB on the Unit 231-B101 and Unit 865-11H1 Heaters, PES does not feel that this constitutes an NSPS modification. However, it should be noted that the future projected NO_x emission rate (0.03 lb/MMBtu) for each of these heaters is expected to meet the NO_x emissions limitations (0.04 lb/MMBtu) set forth in 40 CFR 60.102a(g)(2)(i).

6.3.2 Maximum Achievable Control Technology (MACT)

The target heaters will be subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT) codified in 40 CFR §63.7490. The existing target heaters must be in compliance with Boiler MACT within 180 days of January 31, 2016. The Refinery will demonstrate compliance by performing annual tune-ups of each affected heater and completing a one-time energy assessment.

[9] EPA, 1989. Re: Applicability of NSPS. Letter from Don R. Clay, Acting Assistant EPA Administrator of EPA to Mr. John W. Boston, WEPCO, February 15, 1989.

7.0 PROPOSED PLAN APPROVAL CONDITIONS

PES proposes the following permit conditions and compliance methods for the proposed plan approval. The target heaters will be subject to revised firing rate limits as shown in Tables 7-1 and 7-2 and annual emission limits (TPY) as shown in Tables 7-3 and 7-4.

Table 7-1 Revised Firing Rate Limits for Unmodified Target Heaters

Process Unit	Heater	Proposed Annual Firing Limit (MMBtu/year)	RACT NO_x Emission Rate Limit (lb/MMBtu)[1]
PB Unit 865 HDS	11H2 Reboiler Heater	500,000	0.113
PB Unit 210 Crude	H101 Crude Heater	1,643,000	0.089
PB Unit 210 Crude	H201 Crude Heater	2,172,000	0.03
PB Unit 866 HDS	12H1 Feed Heater	456,000	0.113
PB Unit 868 FCCU	8H101 Recycle Heater	480,000	0.113

[1] See Attachment A for the RACT Analysis that discusses the RACT NO_x emission rate for each target heater.

Table 7-2 Revised Firing Rate Limits for Modified Target Heaters

Process Unit	Heater	Firing Limit	RACT NO_x Emission Rate Limit (lb/MMBtu)
RACT Plan Approval Conditions Pending ULNB Installation			
GP Unit 231 HDS	B101 Feed Heater	91 MMBtu/hr	0.122
PB Unit 865 HDS	11H1 Feed Heater	72.2 MMBtu/hr	0.113
Proposed Conditions after ULNB Installation and Testing			
GP Unit 231 HDS	B101 Feed Heater	856,000 MMBtu/year	0.03 [1]
PB Unit 865 HDS	11H1 Feed Heater	699,000 MMBtu/year	0.03 [1]

[1] The Firing and RACT NO_x Firing Rate Limits will only apply to the Unit 231-B101 and Unit 865-11H1 Heaters after the ULNBs have been successfully installed and tested.

Compliance with the annual firing rate limits will be demonstrated on a rolling 365-day average. The Refinery will monitor the inputs to the heaters including fuel throughput (scf/hour) and heat content (Btu/scf) on a daily basis for compliance with the firing rate limits.

Table 7-3 Proposed Emissions Limits for Unmodified Target Heaters (Based on Projected Actual Emissions)

Target Heater	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	CO (TPY)	VOC (TPY)	NO_x (TPY)	SO_2 (TPY)	Lead (TPY)	CO_2e (TPY)
Unit 865-11H2	1.8	1.8	1.8	20.4	1.3	28.3	0.5	1.2E-04	29,168
Unit 210-H101	6.1	6.1	6.1	66.9	4.4	73.1	2.7	4.0E-04	95,847
Unit 210-H201	8.0	8.0	8.0	88.5	5.8	32.6	3.2	5.3E-04	126,707
Unit 866-12H1	1.7	1.7	1.7	18.6	1.2	25.8	0.5	1.1E-04	26,601
Unit 868-8H101	1.7	1.7	1.7	18.9	1.2	27.1	0.6	1.1E-04	27,054

Table 7-4 Proposed Emissions Limits for Modified Target Heaters (Based on Projected Actual Emissions)

Target Heater	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	CO (TPY)	VOC (TPY)	NO_x (TPY)	SO_2 (TPY)	Lead (TPY)	CO_2e (TPY)
Proposed Conditions after ULNB Installation and Testing [1]									
Unit 231-B101	3.1	3.1	3.1	34.4	2.3	12.8	0.8	2.0E-04	49,253
Unit 865-11H1	2.6	2.6	2.6	28.5	1.9	10.5	0.7	1.7E-04	40,777

[1] The Emissions Limits will only apply to the Unit 231-B101 and Unit 865-11H1 Heaters after the ULNBs have been successfully installed and tested.

Compliance with the annual emission limits (TPY) will be on a rolling 12-month basis.

Attachment A
Reasonably Achievable Control Technology (RACT) analysis

REASONABLY ACHIEVABLE CONTROL TECHNOLOGY ANALYSIS

Philadelphia Energy Solutions Refining and Marketing, LLC. (PES).

Reasonably Achievable Control Technology Analysis for the Heater Firing Rate Increase

August 31, 2012 (Submittal)
September 6, 2012 (Completeness Determination)
September 2013 (Supplement)

Environmental Resources Management
75 Valley Stream Parkway
Suite 200
Malvern, Pennsylvania 19355

List of Tables

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1.0 REASONABLY ACHIEVABLE CONTROL TECHNOLOGY ANALYSIS

The Sunoco, Inc. (R&M)[1] Girard Point Processing Area and Point Breeze Processing Area RACT Plan Approval amended on October 7, 2002 was established for nitrogen oxides (NO_x) and volatile organic compounds (VOCs) and limits the firing rate on the heaters to comply with the RACT regulatory requirements codified in 25 Pa Code §129.91 through §129.95. This application addresses changes to certain NO_x RACT conditions[2]. No changes to VOC RACT conditions are requested. With this application, the Refinery proposes to remove the firing rate limits in the RACT Plan Approval for seven target heaters:

- Unit 231-B101 Heater;
- Unit 865-11H1 Heater;
- Unit 865-11H2 Heater;
- Unit 210-H101 Heater;
- Unit 210-H201 Heater;
- Unit 866-12H1 Heater; and
- Unit 868-8H101 Heater.

1.1 RACT ANALYSIS REQUIREMENTS

As described in 25 Pa Code §129.92(b), each RACT Analysis must include the requirements listed in Table 1-1 below.

[1] The Sunoco Philadelphia Refinery is now owned and operated by Philadelphia Energy Solutions Refining and Marketing, LLC (PES).

[2] The RACT Plan Approval revisions to the target heater firing rate or emission limits are not being requested by PES to comply with any requirements of Consent Decree No. 05-02866 (Fourth Amendment, dated August 17, 2012).

Table 1-1 25 Pa Code §129.92(b) RACT Requirements

25 Pa Code §129.92(b) Requirement	Discussion
A ranking of the available control options for the affected source in descending order of control effectiveness.[1]	• Ultra-low NO_x burners (ULNB) and Selective Catalytic Reduction (SCR) – 96% • Selective Catalytic Reduction – 85% • Ultra-low-NO_x burners – 66 to 76% • Low-NO_x burners and Selective Non-Catalytic Reduction (SNCR) – 70% • Low-NO_x burners (LNB) and Flue Gas Recirculation (FGR) – 55% • Selective Non-Catalytic Reduction – 40%
An evaluation of the technical feasibility of the available control options identified based on physical, chemical and engineering principles. A determination of technical infeasibility should identify technical difficulties restricting the successful use of the control option on the affected source.	• Unit 865-11H1 – The installation of SCR is not possible as there is not adequate plot space available; further, there is not adequate pressure to overcome the SCR pressure drop; therefore, SCR is infeasible. FGR installation would require the installation of mechanical draft burners, which is a major re-design of the unit; therefore FGR is infeasible. • Unit 210-H101 - FGR would not physically fit the plot space; therefore, it is infeasible. • Unit 210-H201 - The installation of SCR is not possible as there is not adequate plot space available; further, there is not adequate pressure to overcome the SCR pressure drop; therefore, SCR is infeasible. FGR installation would require the installation of mechanical draft burners, which is a major re-design of the unit; therefore FGR is infeasible.
A ranking of the technically feasible control options in order of overall control effectiveness for NO_x emissions.	The RACT summary in Appendix A for each target heater ranks the technically feasible controls options by listing them from highest to lowest control effectiveness.
The baseline emissions of NO_x before implementation of each control option ("pre-control emissions").	The "pre-control emissions" are listed in the "Potential Emissions (TPY)" column for each target heater in the RACT summary for each heater in Appendix A.
The estimated emission reduction potential or the estimated control efficiency of each control option.	The estimated emission reduction potential for each control option for each target heater is listed in the "Potential NO_x Reduced (TPY)" column in the RACT summary for each heater in Appendix A. These values based on design firing for each heater.
The estimated emissions after the application of each control option ("post-control emissions").	The "post-control emissions" are listed in the "Maximum Post Control Emissions @ Design Firing (TPY)" column for each target heater in the RACT summary for each heater in Appendix A.
An evaluation of cost effectiveness of each control option consistent with EPA's cost guidance manuals. The cost effectiveness shall be evaluated in terms of dollars per ton of NO_x emissions reduction.	See Appendix A for the RACT Cost Effectiveness Analysis.

[1] NO_x control effectiveness derived from Alternative Control Techniques Document – NO_x Emissions from Process Heaters (Revised) - EPA Emissions Standards Division - EPA-453/R-93-034 and Refinery process knowledge.

1.2 *RACT PLAN APPROVAL CHANGES*

PES is requesting changes to the RACT Plan Approval including updates to presumptive RACT sources and updates to previous RACT determinations on select heaters. For this RACT analysis and future RACT analyses, PES is requesting that the RACT determinations focus on identifying specific NO_x control technology requirements and pollutant emission rates (lb/MMBtu) as RACT. Previously the RACT determinations were identified as hourly firing rate limits (MMBtu/hr) and pollutant emission rates. The basis for the RACT analysis, provided here, now relies on design firing for all heaters.

A summary of requested RACT Plan Approval revisions are found in Table 1-4 at the end of this section.

1.2.1 *Presumptive RACT Revisions*

Three of the target heaters, Unit 865-11H2, Unit 866-12H1, and Unit 868-8H101, previously had firing rate limits less than 50 million British thermal units per hour (MMBtu/hr) and were therefore subject to presumptive RACT NO_x controls established under 25 Pa Code §129.93. Presumptive RACT required the use of combustion tuning rather than physical controls. Because these three heaters are seeking annual equivalent firing rate limits over 50 MMBtu/hr, PES has provided a Case-by-Case RACT analysis in Appendix A for these heaters as a part of this plan approval application along with the other target heaters.

1.2.2 *Modifications to Unit 231-B101 and Unit 865-11H1*

Ultra-low NO_x burners (ULNBs) are planned to be installed on Unit 231-B101 and Unit 865-11H1[3]. PES proposes that the RACT Plan Approval be revised to keep the current RACT limits for hourly firing limit (MMBtu/hr) and NO_x emission rate (lb/MMBtu) in place until the installation of the ULNBs are complete. A new permit condition should be included in Section 2 of the RACT Plan Approval to only allow the removal of the hourly firing limits for the Unit 231-B101 and Unit 865-11H1 heaters after the ULNBs have been successfully installed and stack test results show that the heaters meet the specified NO_x emission rate (0.03 lb/MMBtu). See the proposed RACT limits in Table 1-2 below.

[3] As part of a settlement agreement with the Clean Air Council, PES agreed voluntarily to install ultra-low NO_x burners on Unit 231-B101 Heater and Unit 865-11H1 Heater at the Refinery to further reduce emissions beyond the cuts achieved by the shut-down of the Marcus Hook Refinery.

Table 1-2 Proposed RACT Plan Approval Conditions for Unit 231-B101 and Unit 865-11H1

Heater	Hourly Firing Limit (MMBtu/hr)	NO_x Emission Rate (lb/MMBtu)	RACT NO_x Control
RACT Plan Approval Conditions Pending ULNB Installation			
Unit 231-B101	91	0.122 (refinery fuel gas)	Combustion Tuning
Unit 865-11H1	72.2	0.113 (refinery fuel gas)/0.400 (refinery fuel oil)	Combustion Tuning
Proposed Conditions after ULNB Installation and Testing			
Unit 231-B101	- - -	0.03 (refinery fuel gas)	Combustion Tuning
Unit 865-11H1	- - -	0.03 (refinery fuel gas)	Combustion Tuning

1.2.3 *Cessation of Refinery Fuel Oil Firing*

As discussed under Section 110(l) of the Clean Air Act, while the changes to the RACT Plan Approval include removal of firing rates of seven heaters, the RACT Plan Approval will still provide reasonable further progress toward ozone attainment because PES is also requesting removal of the ability for fuel oil firing for five of the seven heaters. Typically refinery fuel oil firing NO_x emission rates are higher than gaseous fuel-firing NO_x emission rates.

Table 1-3 below shows the change in NO_x maximum emissions, based on the RACT limits for the target heaters based on the removal of the ability for fuel oil firing. The current oil firing NO_x emissions rate limits and hourly firing limits (MMBtu/hr) as well as the proposed gaseous fuel-firing NO_x emission rate limits and design firing (MMBtu/hr) for five of the target heaters were used to determine the total reduction in maximum NO_x emissions associated with the proposed RACT limit changes. This reduction in emissions provides reasonable further progress toward ozone attainment.

Table 1-3 NO_x Emissions Reductions from Cessation of Refinery Fuel Oil Firing

Target Heater	Existing Hourly Firing Limit (MMBtu/ hr)	Oil Firing Emission Limit (lb NO_x/ MMBtu)	Current RACT NO_x (TPY)	Design Firing (MMBtu/ hr)	Gas Firing Proposed Emission Limit (lb NO_x/ MMBtu)	Proposed RACT NO_x (TPY)	Change in NO_x (TPY)
Unit 865-11H1	72.2	0.400	126.5	87.3	0.030	11.5	-115.0
Unit 865-11H2 [1]	49.9	0.113	24.7	64.2	0.113	31.8	7.1
Unit 210-H101	183.0	0.400	320.6	192.0	0.089	74.8	-245.8
Unit 210-H201	242.0	0.400	424.0	254.0	0.030	33.4	-390.6
Unit 866-12H1 [1]	43.0	0.113	21.3	61.2	0.113	30.3	9.0
Total Target Heater NO_x RACT Reduction (TPY)							-735.3

[1] Note that Unit 865-11H2 and Unit 866-12H1 are currently complying with the presumptive RACT limits and do not have oil firing NO_x emission limits. Conservatively, the proposed gas firing NO_x emission limit of 0.113 lb/MMBtu was assumed as the oil firing emission limit for this analysis.

Table 1-4 Summary of RACT Plan Approval Revisions

Section	Revisions Requested
Section 1.A(2)	Revise firing duty of Unit 231-B101 to 104.5 MMBtu/hr.
Section 1.A(11)	Revise firing duty of Unit 210-H101 to 192 MMBtu/hr. Revise firing duty of Unit 210-H201 to 254 MMBtu/hr. Revise the section to remove the firing of refinery fuel oil.
Section 1.A(15)	Revise firing duty of Unit 865-11H1 to 87.3 MMBtu/hr. Revise firing duty of Unit 865-11H2 to 64.2 MMBtu/hr. Revise the section to remove the firing of refinery fuel oil.
Section 1.A(16)	Revise firing duty of Unit 866-12H1 to 61.2 MMBtu/hr. Revise the section to remove the firing of refinery fuel oil.
Section 1.A(19)	Revise firing duty of Unit 868-8H101 to 60.0 MMBtu/hr.
Section 1.B(1)	Add control technology for Unit 210-H201 (ultra-low NO_x burners).
Section 2.A	Add description that ultra-low NO_x burners are planned to be installed on Unit 231-B101 and Unit 865-11H1. Installation will be completed after issuance of plan approval.
Section 2.B	Include combustion tuning as RACT for Unit 865-11H2 and Unit 868-8H101.
Section 2.C	Removal of the heat input caps (MMBtu/hr) for Unit 231-B101 and Unit 210-H201.
New paragraph in Section 2	Add control technologies for Unit 210-H101 (low NO_x burners) and Unit 210-H201 (ultra-low NO_x burners).
New paragraph in Section 3	Add description that original RACT limits apply until the installation of ultra-low NO_x burners on Unit 231-B101 and Unit 865-11H1.
Section 4.B	Add description that NO_x RACT emissions limit for Unit 210-H201 has been established using CEMS.
Section 4.C	Removal of Unit 231-B101 and Unit 865-11H1 Heaters from the table as compliance will be demonstrated through performance testing.
Section 4.C	Updates to add NO_x emission rate for Unit 865-11H2, Unit 866-12H1, and Unit 868-8H101.
Section 4.C	Updates to NO_x emission rate for Unit 210-H201 Heater and removing refinery fuel oil firing NO_x emission limitations for Unit 210-H101 and Unit 210-H201.

1.3 RACT COST EFFECTIVENESS CALCULATIONS

In this application, the cost effectiveness calculations for the RACT analyses were based on the EPA guidance document entitled *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034. PES also used cost information from past Refinery ULNB installations on two heaters (Unit 1332 H-400/H-401 Heater and Unit 137 F-3 Heater). These costs – capital and operation and maintenance (O&M) – were scaled up to 2012 dollar amounts using *Chemical*

Engineering cost indices. PES has also conducted the analysis at the current cost of borrowing capital.

As PES is a recently established company under new ownership in a private equity structure, the cost of borrowing capital (the minimum return that investors expect for providing capital to the company) is considered at a higher risk than many established companies. The cost effectiveness analysis reflects the current cost of capital for PES, which is 21.83%.

1.4 RACT ANALYSIS RESULTS

The RACT cost effectiveness for the subject heaters are calculated at approximately \$6,700 to \$163,000 per ton of NO_x emissions reductions for additional controls beyond those considered part of current heater design and operation. The RACT analysis leads to the following conclusions:

- The Unit 210-H101 Heater already has LNB installed[4]; however, the installation of current generation UNLB is not cost effective.
- Unit 210-H201 has NO_x control today at a permit limit of 0.03 lb/MMBtu, and no further control is deemed to be cost effective as indicated by the RACT analysis.
- With the planned installations of ULNBs on Unit 231-B101 and Unit 865-11H1, as indicated by the RACT analysis, no other control technologies are found to be cost effective.
- As illustrated in Appendix A, for the remaining heaters, additional retrofit NO_x control options beyond combustion tuning are not cost effective. Therefore, combustion tuning is RACT for these heaters.

[4] Burners were considered UNLB when installed, but referred to here as LNB to avoid confusion.

2.0 RACT PLAN APPROVAL PROPOSED CONDITIONS

Based on this RACT analysis, including the RACT cost effectiveness analysis completed in Appendix A, PES is proposing RACT for the seven target heaters as described below. Table 2-1 at the end of this section shows the existing and proposed RACT Plan Approval limits.

2.1 RACT CONTROL EQUIPMENT REQUIREMENTS

Combustion tuning will be RACT for the following heaters: Unit 231-B101 Heater, Unit 865-11H1 Heater, Unit 865-11H2 Heater; Unit 210-H101 Heater; Unit 210 H-201 Heater; Unit 866-12H1 Heater; and Unit 868-8H101 Heater as well as compliance with the RACT NO_x emission rate limit for each heater listed in Table 2-1.

2.2 RACT IMPLEMENTATION SCHEDULE

Sources in Table 2-1 below proposing combustion tuning to comply with RACT requirements of 25 PA Code 129.91(f) shall perform quarterly combustion tuning.

2.3 RACT TESTING REQUIREMENTS AND STACK EMISSION LIMITATIONS

After installation of the ULNB on the Unit 231-B101 and Unit 865-11H1 Heaters, PES shall conduct a one-time performance tests for NO_x. The results of these tests will be submitted to AMS.

The final NO_x RACT emission limits for the Unit 210-H201 Heater shall be established through the use of the Department-approved Continuous Emission Monitoring System (CEMS) currently installed. Compliance with the limitation listed in Table 2-1 below for Unit 210-H201 will be on a 365-day rolling average based on hourly averages of CEM data.

Compliance with emission limits for the Unit 210-H101, Unit 865-11H2, Unit 866-12H1, and Unit 868-8H101 Heaters shall be determined by quarterly stack sampling with a portable NO_x analyzer. After one year sampling, PES may petition AMS for semi-annual monitoring.

All annual combustion tuning shall at a minimum meet the requirements set forth in 25 PA Code 129.93 (b)(2) through (5).

At least thirty (30) days prior to a performance NO_x test, PES shall inform AMS of the date and time of the scheduled test.

2.4 *RACT RECORDKEEPING AND REPORTING REQUIREMENTS*

PES shall maintain a file containing all the records and other data that are required to be collected to demonstrate compliance with NO_x RACT requirements of 25 PA Code 129.91- 129.94.

The records shall provide sufficient data and calculations to clearly demonstrate that the requirements of §129.91-129.94 are met.

Data or information required to determine compliance shall be recorded and maintained in a time frame consistent with the averaging period of the requirement.

Records shall be retained for at least two years and shall be made available to the Department on request.

Table 2-1 RACT Plan Approval Existing and Proposed Limits

Unit	Existing Hourly Firing Limit (MMBtu/hr) [2]	Design Firing (MMBtu/hr)	Emission Rate Limit (lb NO_x/MMBtu)				RACT Control	
			Existing [3]		Proposed [4]		Existing	Proposed
			Gas	Oil	Gas	Oil		
Unit 231-B101	91	104.5	0.122	-	0.03	-	Tuning	Tuning [5]
Unit 865-11H1	72.2	87.3	0.113	0.400	0.03	-	Tuning	Tuning [5]
Unit 865-11H2 [1]	49.9	64.2	-	-	0.113	-	-	Tuning
Unit 210-H101	183	192.0	0.089	0.400	0.089	-	Tuning	Tuning [6]
Unit 210-H201	242	254.0	0.173	0.400	0.03	-	Tuning	Tuning [6]
Unit 866-12H1 [1]	43	61.2	-	-	0.113	-	-	Tuning
Unit 868-8H101 [1]	49.5	60.0	-	-	0.113	-	-	Tuning

1 Units are currently subject to PADEP's presumptive RACT and not subject to specific requirements in the RACT Plan Approval.

2 Compliance with limitation is based on the daily average heat input.

3 Compliance with limitation is based on quarterly stack sampling using a portable NO_x analyzer.

4 The Refinery is only proposing limits for firing natural gas at the target heaters. The Refinery no longer uses refinery fuel oil as a fuel for the Unit 865-11H1, Unit 210-H101, and Unit 210-H201 heaters and proposes to remove the capability to use refinery fuel oil as a fuel from the RACT Plan Approval. For Unit 210-H201, compliance with the emission rate limit will be through the use of Department-approved CEMS currently installed. For heaters other than Unit 210-H201, compliance with limitation is based on quarterly stack sampling using a portable NO_x analyzer.

5 PES is proposing that the current RACT Plan Approval conditions remain in place and the hourly firing rate limits can only be removed after the installation and testing of the ULNBs at Unit 231-B101 and Unit 865-11H1.

6 Control equipment is currently installed; however only combustion tuning is currently required as RACT control for these units in the RACT Plan Approval. The proposed emission rate limits also reflect the presence of control equipment.

CITY OF PHILADELPHIA
DEPARTMENT OF PUBLIC HEALTH
AIR MANAGEMENT SERVICES

RACT PLAN APPROVAL

Effective Date: August 1, 2000

Amended Date: October 7, 2002

These amendments will update RACT requirements for sources affected in the Heater Firing Rate Increase Plan Approval.

Expiration Date: None

Replaces Permit No. None

In accordance with provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and after due consideration of a Reasonably Available Control Technology (RACT) proposal received under the Pennsylvania Code, Title 25, Chapter 129.91 thru 129.95, of the rules and regulations of the Pennsylvania Department of Environmental Protection (PADEP), Air Management Services (AMS) amended the RACT Plan Approval of the Facility below for the source(s) listed in section 1.A. Emission Sources of the attached RACT Plan Approval.

Facility:	~~Sunoco, Inc. (R & M)~~
Owner:	~~Sunoco, Inc.~~
Location:	Girard Point Processing Area located at 3001 Penrose Ave Point Breeze Processing Area located at 3144 Passyunk Ave
Mailing Address:	3144 Passyunk Ave., Philadelphia, PA 19145
SIC Code(s):	2911
Plant ID:	1501 and 1517
Facility Contact:	~~Eric Schneider~~
Phone:	(215) 339~~-2091~~
Permit Contact:	~~Eric Schneider~~
Phone:	(215) 339~~-2091~~
Responsible Official:	~~Vincent J. Kelley~~
Title:	~~Refinery Manager~~

Edward Braun, Chief of Source Registration

10/7/02

Date

The RACT plan approval is subject to the following conditions:

1. The purpose of this Plan Approval is to establish Nitrogen Oxides (NOx)/Volatile Organic Compound (VOC) Reasonably Available Control Technology (RACT) for ~~Sunoco, Inc. (R&M)~~ Girard Point Processing Area and Point Breeze Processing Area. This includes the following emission sources and control equipment:

A. Emission Sources

(1) Process Heaters: Unit 137: F1 heater (415 MMBTU/hr)
F2 heater (155 MMBTU/hr)
F3 heater (60 MMBTU/hr)
Process heaters F1 and F2 burn refinery fuel gas or refinery fuel oil. Heater F3 burns refinery fuel oil.

(2) Process Heater: Unit 231: B-101 heater (~~91~~ MMBTU/hr) Heater fires refinery fuel gas.

(3) Process Heater: Unit 433: H-1 heater (243 MMBTU/hr) Heater fires refinery fuel gas.

(4) Process Heaters: Unit 1332: H-400 heater (186 MMBTU/hr)
H-401 heater (233 MMBTU/hr)
H-600 heater (21.3 MMBTU/hr)
H-601 heater (48 MMBTU/hr)
H-602 heater (49 MMBTU/hr)
H-1 heater (45 MMBTU/hr)
H-2 heater (60 MMBTU/hr)
H-3 heater (43 MMBTU/hr)
These heaters burn refinery fuel gas.

(5) Process Heater: Unit 1232: B-104 heater (70 MMBTU/hr) Heater fires refinery fuel gas.

(6) Boiler House #3: Boiler #37 (495 MMBTU/hr)
Boiler #38 (495 MMBTU/hr)
Boiler #39 (495 MMBTU/hr)
Boiler #40 (660 MMBTU/hr)
These boilers fire refinery fuel gas or refinery fuel oil.

(7) Sludge Incinerator 8832: Unit was 44 MMBTU/hr and burned refinery fuel gas or refinery fuel oil.

(8) Sulfur Recovery Unit 532: SO2 incinerator was 16 MMBTU/hr. Unit burned refinery fuel gas.

(9) 1232 FCCU CO Boiler: CO waste gas combustion unit (580 MMBTU/hr) burns process waste gas, refinery fuel gas and refinery fuel oil.

(10) Asphalt Heater: H1 (12.8 MMBTU/hr)
H2 (12.8 MMBTU/hr)
H3 (12.8 MMBTU/hr)
H5 (12.8 MMBTU/hr)
These heaters burned fire refinery fuel gas.

(11) Crude Unit 210: Section A HTR H101 (~~183~~ MMBTU/hr)
Section B HTR H201 (~~242~~ MMBTU/hr)
Section C HTR 13H1 (235.4 MMBTU/hr)
These heaters above fire refinery fuel gas ~~and refinery fuel oil~~.

(12) Hydrocracker Unit 859: HTR 1H1 (76 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 1H2 (70 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 1H3 (211 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 1H4 (19 MMBTU/hr) Unit fires refinery fuel gas.

(13) Reformer Unit 864: HTR PH3 (80 MMBTU/hr)
HTR PH5 (90 MMBTU/hr)
HTR PH1 (80 MMBTU/hr)
HTR PH2 (45 MMBTU/hr)
HTR PH4 (57 MMBTU/hr)
HTR PH7 (45.5 MMBTU/hr)
HTR PH11 (74 MMBTU/hr)
HTR PH12 (85.1 MMBTU/hr)
These heaters fire refinery fuel gas and refinery fuel oil.

(14) Hydrogen Plant 861: HTR 3H1S (123 MMBTU/hr)
HTR 3H1N (125 MMBTU/hr)
These heaters burned refinery fuel gas.

(15) Distillate HDS Unit 865: HTR 11H1 (~~72.2~~ MMBTU/hr)
HTR 11H2 (~~49.9~~ MMBTU/hr)
These heaters fire refinery fuel gas ~~and refinery fuel oil~~.

(16) Gas Oil HDS Unit 866: HTR 12H1(~~43~~ MMBTU/hr) Heater fires refinery fuel gas ~~and refinery fuel oil~~.

(17) 22 Boiler House: Boiler #1 (169 MMBTU/hr)
Boiler #2 (169 MMBTU/hr)
Boiler #3 (203 MMBTU/hr)
These three boilers burn only refinery fuel gas or natural gas and are equipped with Ultra Low NOx Burners.

(18) Reformer Unit 860: HTR 2H3 (174.67 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 2H5 (155 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 2H1 (49 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 2H2 (69.78 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 2H4 (99.44 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 2H6 (36.7 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 2H7 (59 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
HTR 2H8 (49.6 MMBTU/hr) Unit fires refinery fuel gas and refinery fuel oil.
Boiler 2H9 (165 MMBTU/hr) Unit fires refinery fuel gas or natural gas.

(19) 868 FCCU HTR 8H101 (~~47.92~~ MMBTU/hr) Unit fires refinery fuel gas.

(20) 868 FCCU Catalyst Regenerator

(21) 867 Sulfur Recovery Unit Incinerator

(22) Emergency Flares

(23) Cooling towers

(24) Fugitive leaks: valves, flanges, compressors, pumps, pipes.

B. Control Equipment

(1) Ultra-low NOx burner (ULNB) systems are installed on the following sources to control NOx emissions:
Unit 433 H-1 heater
Unit 1232 B-104 heater
#3 Boiler House boilers #37, #38, #39, and #40.
Unit 210-H201

2. This approval requires and authorizes:

A. The installation of the Ultra Low NOx Burners on 433 H-1 heater, 1232 B-104 heater, and #3 Boiler House boilers #37, #38, #39, and #40 to comply with RACT requirements. The installation of the burners has been completed.

B. ~~Sunoco~~ will use combustion tuning to comply with RACT requirements for the following heaters:

Add description that ultra-low NOx burners are planned to be installed on Unit 231-B101 and Unit 865-11H1. Installation will be completed after issuance of plan approval.

Unit 137: F1 heater, F2 heater, F3 heater
Unit 231: B-101 heater
Unit 1332: H-400 heater, H-401 heater, H-2 heater
Crude Unit: 210A HTR H101, 210B HTR H201, 210C HTR 13H1
Hydrocracker Unit 859: HTR 1H1, HTR 1H2, HTR 1H3
Reformer Unit 864: HTR PH3, HTR PH5, HTR PH1, HTR PH2, HTR PH4, HTR PH11, HTR PH12
Hydrogen Plant 861: HTR 3H1S, HTR 3H1N
Distillate HDS Unit 865: HTR 11H1
Reformer Unit 860: HTR 2H3, HTR 2H5, HTR 2H4, HTR 2H2, HTR 2H7
Gas Oil HDS Unit 866: HTR 12H1(43 MMBTU/hr)
Distillate HDS Unit 865: HTR 11H2 and HDS Unit 868: HTR 8H101

C. All fuel burning sources will be capped at the heat input specified in the table below. If ~~Sunoco~~ desires to raise the cap, a RACT evaluation will have to be performed at that new heat input. The economic evaluation will be made using cost of living increases. Changes will require a resubmission as revision to the PA State Implementation Plan. The applicant shall bear the cost of public hearing and notification required for EPA approval as stipulated in 25 PA Code §129.9(h). Modifications or changes may require additional controls or more strict emission limits depending on the applicable regulation triggered as a result of the modification or change.

Process Unit	Source	Heat Input Cap (MMBTU/hr)
Unit 137:	F1 heater	415
	F2 heater	155
~~Unit 231:~~	~~B-101 heater~~	~~91~~
Unit 433:	H-1 heater	243
Unit 1332:	H-400 heater	186
Unit 1232:	B-104 heater	70
Boiler House #3:	Boilers #37, #38, #39	495
	Boiler #40	660
~~Crude Unit 210B:~~	~~HTR H201~~	~~242~~
Hydrocracker Unit 859:	HTR 1H1	76
	HTR 1H2	70
Reformer Unit 864:	HTR PH3	80
	HTR PH5	90
	HTR PH2	45
	HTR PH4	57
Hydrogen Plant 861:	HTR 3H1S	123
	HTR 3H1N	125

D. ~~Sunoco~~ shall monitor all fuel input to all heaters and boilers with BTU limitations on a daily basis to insure capacity limits are not exceeded or ~~sun~~ shall install fuel limiting devices on the heaters or boilers to keep capacities below allowable. The compliance method must be in place by June 30th 2000.

E. All fuel combustion sources with heat input equal to or greater than 20 MMBTU/hr and less than 50 MMBTU/hr shall comply with applicable presumptive RACT requirements of 25 PA Code 129.93(b)(2)-(5). All fuel combustion sources with heat input less than 20 MMBTU/hr shall comply with presumptive RACT requirements of 25 PA Code 129.93(c).

F. RACT for 22 Boiler House: Boiler #1, Boiler #2, and Boiler #3 is combustion tuning.

G. RACT for Reformer Unit 860 HTR 2H9 is combustion tuning.

H. The 868 FCCU NOx emissions shall be limited to 569 tons per year calculated on a 365 day rolling average basis. ~~Sun~~ shall follow good combustion practices controlling the level of excess oxygen and CO promoter in the regenerator to minimize NOx emissions from the regenerator.

J. ~~Sunoco~~ shall utilize an inspection and maintenance/monitoring program for VOC fugitive emissions from cooling towers.

K. ~~Sunoco~~ shall utilize a fugitive emissions leak detection and repair program (LDAR) for all valves, pumps, flanges, and compressors in VOC service. All applicable equipment shall be tagged by May 31, 1995. Monitoring of components shall begin by July 31, 1995 and shall be conducted on a quarterly basis (gaseous service) and an annual basis (liquid service) for all sources not covered under an existing LDAR program.

L. The 1232 FCCU CO Boiler: CO waste gas combustion unit (580 MMBTU/hr) shall comply with the presumptive RACT requirements of 25 PA Code 129.93(c)(4), which is installation, maintenance and operation of the source in accordance with manufacturers specifications.

Add control technologies for Unit 210-H101 (low NOx burners) and Unit 210-H201 (ultra-low NOx burners).

3. RACT Implementation Schedule

A. Upon issuance of this approval, ~~Sunoco, Inc. (R&M), Inc.~~ shall begin immediate implementation of the measures necessary to comply with the approved RACT proposal.

B. Sources proposing combustion tuning to comply with RACT requirements of 25 PA Code 129.91(f) shall perform the annual combustion tuning by December 31st of each year not to exceed 12 months between tunings.

C. Sources applicable to presumptive RACT requirements of 25 PA Code 129.93(b)(2) shall complete the annual adjustment or tune-up by December 31st of each year not to exceed 12 months between tunings.

D. Sources proposing installing Ultra Low NOx Burners to comply with RACT requirements of 25 PA Code 129.91(f) shall perform combustion tuning annually by Decem

Add description that original RACT limits apply until the installation of ultra-low NOx burners on Unit 231-B101 and Unit 865-11H1.

4. Testing Requirements and Stack Emission Limitations

A. For units installing ULNB, ~~Sunoco~~ shall conduct performance tests for NOx. The results of these tests have been submitted to AMS.

B. The final NOx RACT emission limits for the #3 Boiler House boilers, 137 Unit F1 heater, #22 Boiler House boilers: #1, 2, & 3 and the 860 unit Boiler 2H9 have been established through the use of Department approved Continuous Emission Monitoring System (CEMS). Compliance with the limitation listed below will be on a 30 day rolling average based on hourly averages of CEM data.

Source	Limitation
Boiler House #3 – boilers #37, #38, #39, and #40	0.330 lbs. NOx/MMBTU
137 Unit F1 heater	0.230 lbs. NOx/MMBTU
Reformer Unit 860 Boiler 2H9	0.20 lbs. NOx/MMBTU
#22 Boiler House – boilers #1, #2, and #3	0.20 lbs. NOx/MMBTU

C. Compliance with emission limits for combustion sources listed below shall be determined by quarterly stack sampling with a portable NOx analyzer. After one year sampling, ~~Sunoco~~ may petition AMS for semi-annual monitoring. AMS may, at any time, require three one-hour stack tests per fuel type for each unit where fuels can be fired separately. AMS may, at any time, require three one-hour stack tests for dual-fuel type combustion sources where

Add description that NOx RACT emission limit for Unit 210-H201 has been established based on a rolling 365-day average using CEMS.

both fuels must be fired at the same time and compliance with emission limits will be through the use of one set of three one-hour stack tests.

	Limitation (lbs. NOx/MMBTU)	
Source	Gas	Oil
Process Heater Unit 433 ~~H-1 heater~~	0.060	N/A
Process Heater Unit 1332 H-400 heater	0.156	N/A
Process Heater Unit 1332 H-401 heater	0.156	N/A
Crude Unit 210A HTR H101	0.089	~~0.4~~
Crude Unit 210B HTR H201	~~0.173~~	~~0.4~~
Crude Unit 210C HTR 13H1	0.104	0.4
Hydrocracker Unit 859 HTR 1H3	0.134	0.4
Hydrogen Plant 861 HTR3H1S	0.133	N/A
Hydrogen Plant 861 HTR3H1N	0.133	N/A
F-2 @ 137 Unit	0.257	0.4
F-3 @ 137 Unit	N/A	0.4
~~B-101@ 231 Unit~~	~~0.122~~	~~N/A~~
H-2 @ 1332 Unit	0.300	N/A
B-104 @ 1232 Unit	0.177	N/A
1H-1 @ 859 Unit	0.123	0.4
1H-2 @ 859 Unit	0.123	0.4
PH-3 @ 864 Unit	0.284	0.4
PH-5 @ 864 Unit	0.283	0.4
PH-1 @ 864 Unit	0.167	0.4
PH-4 @ 864 Unit	0.102	0.4
PH-11 @ 864 Unit	0.145	0.4
PH-12 @ 864 Unit	0.119	0.4
~~11H-1 @ 865 Unit~~	~~0.113~~	~~0.4~~
2H-3 @ 860 Unit	0.163	0.4
2H-5 @ 860 Unit	0.163	0.4
2H-2 @ 860 Unit	0.350	0.4
2H-4 @ 860 Unit	0.270	0.4
2H-7 @ 860 Unit	0.157	0.4

Add NOx emission rate for Unit 865-11H2, Unit 866-12H1, and Unit 868-8H101

D. All annual combustion tuning shall at a minimum meet the requirements set forth in 129.93 (b)(2) through (5).

E. At least thirty (30) days prior to a performance NOx test, ~~Sunoco~~ shall inform AMS of the date and time of the scheduled test.

5. Recordkeeping and Reporting Requirements

A. The permittee shall maintain a file containing all the records and other data that are required to be collected to demonstrate compliance with NOx/VOC RACT requirements of 25 PA Code 129.91 - 129.94.

B. The records shall provide sufficient data and calculations to clearly demonstrate that the requirements of §129.91-129.94 are met.

C. Data or information required to determine compliance shall be recorded and maintained in a time frame consistent with the averaging period of the requirement.

D. Records shall be retained for at least two years and shall be made available to the Department on request.

6. The operation of the aforementioned sources shall not at any time result in the emission of visible air contaminants in excess of the limitations specified in Section 123.41, particulate matter in excess of the limitations specified in Section 123.11 or sulfur oxides in excess of the limitations specified in Section 123.22, all Sections of Chapter 123 of Article III of the Rules and Regulations of the Department of Environmental Resources, or in the emission of any of these or any

other type of air contaminant in excess of the limitations specified in, or established pursuant to, any other applicable rule or regulation contained in Article III.

7. The company shall not impose conditions upon or otherwise restrict the Department's access to the aforementioned source(s) and/or any associated air cleaning device(s) and shall allow the Department to have access at any time to said source(s) and associated air cleaning device(s) with such measuring and recording equipment, including equipment recording visual observations, as the Department deems necessary and proper for performing its duties and for the effective enforcement of the Air Pollution Control Act.

8. Revisions to any emission limitations incorporated in this RACT Approval will require resubmission as revision to the PA State Implementation Plan. The applicant shall bear the cost of public hearing and notification required for EPA approval as stipulated in 25 PA Code §129.9(h).

Appendix A
RACT Cost Effectiveness Analysis

NOx RACT Control Cost Effectiveness
Cost Effectiveness Summary

Control Option	Cost Effectiveness ($/Ton)						
	Unit 231-B101	Unit 865-11H1	Unit 865-11H2	Unit 210-H101	Unit 210-H201	Unit 866-12H1	Unit 868-8H101
ULNB & SCR	NA	NA	34,287	30,796	NA	34,831	35,060
SCR	102,243	NA	32,909	27,397	NA	33,524	33,782
ULNB	NA	NA	6,737	9,477	NA	6,737	6,737
LNB & SNCR	NA	NA	11,045	57,667	162,271	11,331	14,513
LNB & FGR	NA	NA	8,704	NA	NA	8,960	12,965
SNCR	39,924	42,874	13,132	10,825	28,098	13,379	13,482

Assumptions for all heaters:

Number of Years (n)	10	
Interest Rate, % (i)	21.83	Based on 90% equity cost of the average Carlyle energy funds and 10% after tax debt cost.
Annualized Cost Factor (ACF)	0.253	

$$ACF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001 - Equation 2.8a

Year	*Chemical Engineering* Cost Index
1986	318.4
1991	361
2012	582.2
Cost Escalation Factor for SCR[1]	1.83
Cost Escalation Factor for LNB, SNCR, and FGR[2]	1.61

[1] Cost data from *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034 scaled from 1986 to 2012 costs using the Cost Escalation Factor.

[2] Cost data from *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034 scaled from 1991 to 2012 costs using the Cost Escalation Factor.

Source		Control Efficiency	Comment
Ultra low-NO_x burners and Selective Catalytic Reduction	ULNB & SCR	96%	Combining both removal efficiencies of ULNB and SCR.
Selective Catalytic Reduction	SCR	85%	Based on Unit 1332 performance.
Ultra low-NO_x burners	ULNB	66 to 87%	Based on vendor experience at 0.03 lb/MMBtu.
Low-NO_x burners and Selective Non-Catalytic Reduction	LNB & SNCR	70%	Combining both removal efficiencies. Assumes 50% control efficiency for LNB and 40% control efficiency for SNCR. *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034.
Low-NO_x burners and Flue Gas Recirculation	LNB & FGR	55%	*Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034.
Selective Non-Catalytic Reduction	SNCR	40%	Heater stack temperature below 700°F results in low NO_x removal efficiency. EPA Air Pollution Control Technology Fact Sheet - EPA-452/F-03-031.

Source Name	Design Capacity (MMBtu/hr)	NO_x Emission Rate (lb/MMBtu)	Number of Burners	Summary of Technical Infeasibilities for NO_x Control
Unit 231-B101	104.5	0.030	26	None.
Unit 865-11H1	87.3	0.030	8	SCR would not physically fit the plot space and there is not adequate pressure to overcome the SCR pressure drop; therefore, SCR is infeasible. FGR installation would require the installation of mechanical draft burners, which is a major re-design of the unit; therefore FGR is infeasible.
Unit 865-11H2	64.2	0.113	8	None.
Unit 210-H101	192.0	0.089	6	FGR would not physically fit the plot space; therefore, it is infeasible.
Unit 210-H201	254.0	0.030	8	SCR would not physically fit the plot space and there is not adequate pressure to overcome the SCR pressure drop; therefore, SCR is infeasible. FGR installation would require the installation of mechanical draft burners, which is a major re-design of the unit; therefore FGR is infeasible.
Unit 866-12H1	61.2	0.113	6	None.
Unit 868-8H101	60.0	0.113	4	None.

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034
All costs are scaled from 2012 U.S. dollars using the appropriate Cost Escalation Factor.

Capital Cost of Low NO_x Burners (page 6-4 and 6-5):

$$TCI = 30{,}000 + HQ[5{,}230 - (622 \times BQ) + (26.1 \times BQ^2)]$$

Where:
TCI = Total Capital Investment
HQ = heater capacity (GJ/hr)
BQ = burner heat release rate (GJ/hr)
BQ = HQ/NB x (1.158 + 8/HQ)
NB = number of burners

Capital Cost of Ultra-low NO_x Burners:
See the "Refinery ULNB Control Costs" tab for capital cost details for Ultra-low NO_x Burners

Capital Cost of Selective Non-Catalytic Reduction (page 6-7):

$$TCI = 31{,}850(HQ)^{0.6}$$

HQ = heater capacity (GJ/hr)

Operating Cost of Selective Non-Catalytic Reduction (page 6-8):

$$NH_3\ cost\ = Q\ \times\ (lb/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{\$0.125}{lb\ NH_3}\right) \times \left(8{,}760\frac{hours}{year}\right)$$

Where:
Q = heater capacity, MMBtu/hr

$$Electricty\ cost = \left(\frac{0.3\ kWh}{ton\ NH_3}\right) \times \left(\frac{ton\ NH_3}{year}\right) \times \left(\frac{\$0.06}{kWh}\right)$$

Where:

$$\frac{ton\ NH_3}{year} = Q\ \times\ (lb\ NO_x/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{ton}{2000\ lb}\right) \times \left(8{,}760\frac{hours}{year}\right)$$

Capital Cost of Selective Catalytic Reduction (page 6-8):

$$TCI = 1{,}373{,}000 \times \left(\frac{Q}{48.5}\right)^{0.6} + 49{,}000 \times \left(\frac{Q}{485}\right)$$

Where:
Q = heater capacity, MMBtu/hr

Operating Cost of Selective Catalytic Reduction (page 6-9):

$$NH_3\ cost = Q\ \times\ (lb/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{\$0.125}{lb\ NH_3}\right) \times \left(\frac{8{,}760\ hours}{year}\right)$$

Where:
Q = heater capacity, MMBtu/hr
Note the capacity factor has been assumed to be equal to 1; therefore, the capacity factor term has been omitted.

$$Catalyst\ Replacement\ Cost = 49{,}000 \times \frac{Q}{48.5}/5\ years$$

$$Electricty\ cost = \left(\frac{0.3\ kWh}{ton\ NH_3}\right) \times \left(\frac{ton\ NH_3}{year}\right) \times \left(\frac{\$0.06}{kWh}\right)$$

Where:

$$\frac{ton\ NH_3}{year} = Q\ \times\ (lb\ NO_x/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{ton}{2000\ lb}\right) \times \left(8{,}760\frac{hours}{year}\right)$$

Capital Cost of Flue Gas Recirculation (page 6-9):

$$TCI = 12{,}800(HQ)^{0.6}$$

Where:
HQ = heater capacity (GJ/hr)

Operating Cost of Flue Gas Recirculation (page 6-10):

$$Electricty\ cost = (motor\ hp) \times \left(\frac{0.75\ kW}{hp}\right) \times \left(\frac{8{,}760\ hours}{year}\right) \times \left(\frac{\$0.06}{kWh}\right)$$

Where:
motor hp = FGR fan motor horsepower, (1/5) x (Q)
Q = heater capacity, MMBtu/hr

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Ultra Low NO_x Burner Costs - from PES Refinery Project Experience

Economic Data	Heater Fired Duty (MMBtu/hr)	Number of Burners	Burner Heat Release (MMBtu/hr/burner)	Base Year ULNB Cost ($/burner)	Normalized Cost ($/MMBtu/hr)
1332 H-400/H-401 Heater	419	54	7.8	$50,000	$6,444
137 F-3 Heater	60	4	15	$80,500	$5,367
				Average	$5,905

Source Name	Design Capacity (MMBtu/hr)	ULNB Capital Cost Using ($/MMBtu/hr)	ULNB Total Capital Investment
Unit 231-B101	104.5	$617,103	NA
Unit 865-11H1	87.3	$515,532	NA
Unit 865-11H2	64.2	$379,120	$559,581
Unit 210-H101	192.0	$1,133,816	$1,673,512
Unit 210-H201	254.0	$1,499,944	NA
Unit 866-12H1	61.2	$361,404	$533,432
Unit 868-8H101	60.0	$354,317	$522,973

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 231-B101 RACT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	104.5	0.03	13.7	96%	0.5	13.2	NA	NA	NA	NA
SCR	104.5	0.03	13.7	85%	2.1	11.7	4,118,447	149,357	1,193,342	102,243
LNB & SNCR	104.5	0.03	13.7	70%	4.1	9.6	NA	NA	NA	NA
LNB & FGR	104.5	0.03	13.7	55%	6.2	7.6	NA	NA	NA	NA
SNCR	104.5	0.03	13.7	40%	8.2	5.5	773,123	23,307	219,286	39,924
ULNB	104.5	0.03	13.7	0%	13.7	0.0	NA	NA	NA	NA
Calculation			= A * B * 8760 / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Notes:
[1] ULNB are planned to be installed on the Unit 231-B101 heater and the current emission rate is assumed to be 0.03 lb/MMBtu.
[2] See "RACT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 231-B101**	
Control	**SCR**	
Rated Heat Input	**104.5**	**MMBtu/hr**
Number of Burners	**26.0**	**Burners**
Baseline Actual Emissions	**13.73**	**tpy**
Current Emission Rate	**0.030**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**110.3**	**GJ/hr**
Burner Heat Release Rate	**5.2**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	3,998,493
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**3,998,493**
Direct Installation Costs	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**3,998,493**
INDIRECT INSTALLATION COSTS	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	119,955
TOTAL INDIRECT COSTS, IC	**119,955**
TOTAL CAPITAL INVESTMENT (TCI)	**4,118,447**

COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			113,257
			113,257
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			2,046
Catalyst Replacement Cost			34,054
Electricity Cost			0.1
Subtotal - Utilities			**36,100**
TOTAL ANNUAL DIRECT COSTS[a]			**149,357**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**149,357**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			4,118,447
TOTAL ANNUAL CAPITAL REQUIREMENT			**1,043,985**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**1,193,342**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 231-B101**	
Control	**SNCR**	
Rated Heat Input	**104.5**	**MMBtu/hr**
Number of Burners	**26.0**	**Burners**
Baseline Actual Emissions	**13.73**	**tpy**
Current Emission Rate	**0.030**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**110.3**	**GJ/hr**
Burner Heat Release Rate	**5.2**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	750,605
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**750,605**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**750,605**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	22,518
TOTAL INDIRECT COSTS, IC		**22,518**
TOTAL CAPITAL INVESTMENT (TCI)		**773,123**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			21,261
			21,261
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			2,046
Electricity Cost			0.1
Subtotal - Utilities			**2,046**
TOTAL ANNUAL DIRECT COSTS[a]			**23,307**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**23,307**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			773,123
TOTAL ANNUAL CAPITAL REQUIREMENT			**195,979**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**219,286**

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 865-11H1 RACT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	87.3	0.03	11.5	96%	0.5	11.0	NA	NA	NA	NA
SCR	87.3	0.03	11.5	85%	1.7	9.8	NA	NA	NA	NA
LNB & SNCR	87.3	0.03	11.5	70%	3.4	8.0	NA	NA	NA	NA
LNB & FGR	87.3	0.03	11.5	55%	5.2	6.3	NA	NA	NA	NA
SNCR	87.3	0.03	11.5	40%	6.9	4.6	694,045	20,796	196,729	42,874
ULNB	87.3	0.03	11.5	0%	11.5	0.0	NA	NA	NA	NA
Calculation			= A * B * 8760 / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Technical Infeasibilities:
SCR would not physically fit the plot space and there is not adequate pressure to overcome the SCR pressure drop; therefore, SCR is infeasible
FGR installation would require the installation of mechanical draft burners, which is a major re-design of the unit; therefore FGR is infeasible
Notes:
[1] ULNB are planned to be installed on the Unit 865-11H1 heater and the current emission rate is assumed to be 0.03 lb/MMBtu.
[2] See "RACT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 865-11H1**	
Control	**SNCR**	
Rated Heat Input	**87.3**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**11.47**	**tpy**
Current Emission Rate	**0.030**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**92.1**	**GJ/hr**
Burner Heat Release Rate	**14.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:		COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	673,830
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**673,830**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**673,830**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	20,215
TOTAL INDIRECT COSTS, IC		**20,215**
TOTAL CAPITAL INVESTMENT (TCI)		**694,045**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		19,086
		19,086
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		1,709
Electricity Cost		0.1
Subtotal - Utilities		**1,709**
TOTAL ANNUAL DIRECT COSTS[a]		**20,796**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**20,796**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		694,045
TOTAL ANNUAL CAPITAL REQUIREMENT		**175,933**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**196,729**

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 865-11H2 RACT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	64.2	0.113	31.8	96%	1.3	30.5	3,631,525	125,523	1,046,078	34,287
SCR	64.2	0.113	31.8	85%	4.8	27.0	3,071,944	110,135	888,841	32,909
ULNB	64.2	0.113	31.8	73%	8.4	23.3	559,581	15,388	157,237	6,737
LNB & SNCR	64.2	0.113	31.8	70%	9.5	22.2	857,483	28,316	245,679	11,045
LNB & FGR	64.2	0.113	31.8	55%	14.3	17.5	512,272	22,250	152,106	8,704
SNCR	64.2	0.113	31.8	40%	19.1	12.7	577,165	20,607	166,913	13,132
Calculation			= A * B * 8760 / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Notes:
[1] Unit 865-11H2 is projected to be above PADEP presumptive RACT firing limits and assumed NO_x emission rate limit of 0.113 lb/MMBtu is used.
[2] See "RACT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 865-11H2**	
Control	**ULNB & SCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**31.78**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**96%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from ***Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)*** **- EPA-453/R-93-034**

COST COMPONENT:	COST ($)
DIRECT COSTS - ULNB	
Purchased Equipment Costs	
Equipment Cost (EC)	379,120
Instrumentation (10% of EC)	37,912
Sales taxes (5% of EC)	18,956
Freight (8% of EC)	30,330
Subtotal - Purchased Equipment Costs (PEC)	**466,317**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - ULNB	**466,317**
INDIRECT INSTALLATION COSTS - ULNB	
Engineering Costs (5% of PEC)	23,316
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	46,632
Start-up (1% of PEC)	4,663
Performance Test (1% of PEC)	4,663
Contingency (3% of PEC)	13,990
TOTAL INDIRECT COSTS, IC - ULNB	**93,263**
DIRECT COSTS - SCR	
Purchased Equipment Costs	
Equipment Cost (EC)	2,982,470
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,982,470**
Direct Installation Costs	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SCR	**2,982,470**
INDIRECT INSTALLATION COSTS - SCR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	89,474
TOTAL INDIRECT COSTS, IC - SCR	**89,474**
TOTAL CAPITAL INVESTMENT (TCI) - ULNB	**559,581**
TOTAL CAPITAL INVESTMENT (TCI) - SCR	**3,071,944**
TOTAL CAPITAL INVESTMENT (TCI)	**3,631,525**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		99,867
		99,867
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,735
Catalyst Replacement Cost		20,921
Electricity Cost		0.3
Subtotal - Utilities		**25,656**
TOTAL ANNUAL DIRECT COSTS"		**125,523**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**125,523**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		3,631,525
TOTAL ANNUAL CAPITAL REQUIREMENT		**920,555**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**1,046,078**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 865-11H2**	
Control	**SCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**31.78**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	2,982,470
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,982,470**
Direct Installation Costs	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**2,982,470**
INDIRECT INSTALLATION COSTS	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	89,474
TOTAL INDIRECT COSTS, IC	**89,474**
TOTAL CAPITAL INVESTMENT (TCI)	**3,071,944**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			84,478
			84,478
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,735
Catalyst Replacement Cost			20,921
Electricity Cost			0.3
Subtotal - Utilities			**25,656**
TOTAL ANNUAL DIRECT COSTS[a]			**110,135**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**110,135**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			3,071,944
TOTAL ANNUAL CAPITAL REQUIREMENT			**778,707**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**888,841**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 865-11H2**	
Control	**ULNB**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**31.78**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**73%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	379,120
	Instrumentation (10% of EC)	37,912
	Sales taxes (5% of EC)	18,956
	Freight (8% of EC)	30,330
	Subtotal - Purchased Equipment Costs (PEC)	**466,317**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**466,317**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	23,316
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	46,632
	Start-up (1% of PEC)	4,663
	Performance Test (1% of PEC)	4,663
	Contingency (3% of PEC)	13,990
TOTAL INDIRECT COSTS, IC		**93,263**
TOTAL CAPITAL INVESTMENT (TCI)		**559,581**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			15,388
			15,388
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
None			
Subtotal - Utilities			**0.0**
TOTAL ANNUAL DIRECT COSTS[a]			**15,388**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**15,388**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			559,581
TOTAL ANNUAL CAPITAL REQUIREMENT			**141,848**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**157,237**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 865-11H2**	
Control	**LNB & SNCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**31.78**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	189,917
Instrumentation (10% of EC)	18,992
Sales taxes (5% of EC)	9,496
Freight (8% of EC)	15,193
Subtotal - Purchased Equipment Costs (PEC)	**233,598**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**233,598**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	11,680
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	23,360
Start-up (1% of PEC)	2,336
Performance Test (1% of PEC)	2,336
Contingency (3% of PEC)	7,008
TOTAL INDIRECT COSTS, IC - LNB	**46,720**
DIRECT COSTS - SNCR	
Purchased Equipment Costs	
Equipment Cost (EC)	560,355
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**560,355**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR	**560,355**
INDIRECT INSTALLATION COSTS - SNCR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	16,811
TOTAL INDIRECT COSTS, IC - SNCR	**16,811**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**280,318**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR	**577,165**
TOTAL CAPITAL INVESTMENT (TCI)	**857,483**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		23,581
		23,581
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,735
Electricity Cost		0.3
Subtotal - Utilities		**4,735**
TOTAL ANNUAL DIRECT COSTS[a]		**28,316**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**28,316**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		857,483
TOTAL ANNUAL CAPITAL REQUIREMENT		**217,363**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**245,679**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 865-11H2**	
Control	**LNB & FGR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**31.78**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**55%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	COST ($)
DIRECT COSTS - LNB		
	Purchased Equipment Costs	
	Equipment Cost (EC)	189,917
	Instrumentation (10% of EC)	18,992
	Sales taxes (5% of EC)	9,496
	Freight (8% of EC)	15,193
	Subtotal - Purchased Equipment Costs (PEC)	**233,598**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB		**233,598**
INDIRECT INSTALLATION COSTS - LNB		
	Engineering Costs (5% of PEC)	11,680
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	23,360
	Start-up (1% of PEC)	2,336
	Performance Test (1% of PEC)	2,336
	Contingency (3% of PEC)	7,008
TOTAL INDIRECT COSTS, IC - LNB		**46,720**
DIRECT COSTS - FGR		
	Purchased Equipment Costs	
	Equipment Cost (EC)	225,197
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**225,197**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - FGR		**225,197**
INDIRECT INSTALLATION COSTS - FGR		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	6,756
TOTAL INDIRECT COSTS, IC - FGR		**6,756**
TOTAL CAPITAL INVESTMENT (TCI) - LNB		**280,318**
TOTAL CAPITAL INVESTMENT (TCI) - FGR		**231,953**
TOTAL CAPITAL INVESTMENT (TCI)		**512,272**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		14,087
		14,087
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Electricity Cost		8,163
Subtotal - Utilities		**8,163**
TOTAL ANNUAL DIRECT COSTS[a]		**22,250**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**22,250**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		512,272
TOTAL ANNUAL CAPITAL REQUIREMENT		**129,856**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**152,106**

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Source	**Unit 865-11H2**	
Control	**SNCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**31.78**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	560,355
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**560,355**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**560,355**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	16,811
TOTAL INDIRECT COSTS, IC		**16,811**
TOTAL CAPITAL INVESTMENT (TCI)		**577,165**

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COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			15,872
			15,872
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,735
Electricity Cost			0.3
Subtotal - Utilities			**4,735**
TOTAL ANNUAL DIRECT COSTS[a]			**20,607**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**20,607**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			577,165
TOTAL ANNUAL CAPITAL REQUIREMENT			**146,306**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**166,913**

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Unit 210-H101 RACT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	192	0.089	74.8	96%	3.0	71.9	7,613,995	283,106	2,213,176	30,796
SCR	192	0.089	74.8	85%	11.2	63.6	5,940,483	237,084	1,742,936	27,397
LNB & SNCR	192	0.089	74.8	70%	22.5	52.4	10,712,635	305,750	3,021,296	57,667
ULNB	192	0.089	74.8	66%	25.2	49.6	1,673,512	46,022	470,240	9,477
LNB & FGR	192	0.089	74.8	55%	33.7	41.2	NA	NA	NA	NA
SNCR	192	0.089	74.8	40%	44.9	29.9	1,113,678	41,779	324,085	10,825
Calculation			= A * B * 8760 / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Technical Infeasibilities:
FGR would not physically fit the plot space; therefore, it is infeasible.
Notes:
[1] Current generation UNLB is considered to be 0.03 lb/MMBtu, which represents a 66% reduction from 0.089 lb/MMBtu.
[2] See "RACT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

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NOx RACT Control Cost Effectiveness

Source	**Unit 210-H101**	
Control	**ULNB & SCR**	
Rated Heat Input	**192.0**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**74.85**	**tpy**
Current Emission Rate	**0.089**	**lb/MMBtu**
Control Efficiency	**96%**	
Heater Capacity	**202.6**	**GJ/hr**
Burner Heat Release Rate	**40.4**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - ULNB	
Purchased Equipment Costs	
Equipment Cost (EC)	1,133,816
Instrumentation (10% of EC)	113,382
Sales taxes (5% of EC)	56,691
Freight (8% of EC)	90,705
Subtotal - Purchased Equipment Costs (PEC)	**1,394,593**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - ULNB	**1,394,593**
INDIRECT INSTALLATION COSTS - ULNB	
Engineering Costs (5% of PEC)	69,730
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	139,459
Start-up (1% of PEC)	13,946
Performance Test (1% of PEC)	13,946
Contingency (3% of PEC)	41,838
TOTAL INDIRECT COSTS, IC - ULNB	**278,919**
DIRECT COSTS - SCR	
Purchased Equipment Costs	
Equipment Cost (EC)	5,767,459
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**5,767,459**
Direct Installation Costs	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SCR	**5,767,459**
INDIRECT INSTALLATION COSTS - SCR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	173,024
TOTAL INDIRECT COSTS, IC - SCR	**173,024**
TOTAL CAPITAL INVESTMENT (TCI) - ULNB	**1,673,512**
TOTAL CAPITAL INVESTMENT (TCI) - SCR	**5,940,483**
TOTAL CAPITAL INVESTMENT (TCI)	**7,613,995**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		209,385
		209,385
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		11,152
Catalyst Replacement Cost		62,568
Electricity Cost		0.8
Subtotal - Utilities		**73,721**
TOTAL ANNUAL DIRECT COSTS"		**283,106**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**283,106**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		7,613,995
TOTAL ANNUAL CAPITAL REQUIREMENT		**1,930,071**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**2,213,176**

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Source	**Unit 210-H101**	
Control	**SCR**	
Rated Heat Input	**192.0**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**74.85**	**tpy**
Current Emission Rate	**0.089**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**202.6**	**GJ/hr**
Burner Heat Release Rate	**40.4**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	5,767,459
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**5,767,459**
	Direct Installation Costs	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**5,767,459**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	173,024
TOTAL INDIRECT COSTS, IC		**173,024**
TOTAL CAPITAL INVESTMENT (TCI)		**5,940,483**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		163,363
		163,363
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		11,152
Catalyst Replacement Cost		62,568
Electricity Cost		0.8
Subtotal - Utilities		**73,721**
TOTAL ANNUAL DIRECT COSTS[a]		**237,084**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**237,084**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		5,940,483
TOTAL ANNUAL CAPITAL REQUIREMENT		**1,505,852**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**1,742,936**

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Source	**Unit 210-H101**	
Control	**LNB & SNCR**	
Rated Heat Input	**192.0**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**74.85**	**tpy**
Current Emission Rate	**0.089**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**202.6**	**GJ/hr**
Burner Heat Release Rate	**40.4**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS - LNB		
	Purchased Equipment Costs	
	Equipment Cost (EC)	6,503,358
	Instrumentation (10% of EC)	650,336
	Sales taxes (5% of EC)	325,168
	Freight (8% of EC)	520,269
	Subtotal - Purchased Equipment Costs (PEC)	**7,999,131**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB		**7,999,131**
INDIRECT INSTALLATION COSTS - LNB		
	Engineering Costs (5% of PEC)	399,957
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	799,913
	Start-up (1% of PEC)	79,991
	Performance Test (1% of PEC)	79,991
	Contingency (3% of PEC)	239,974
TOTAL INDIRECT COSTS, IC - LNB		**1,599,826**
DIRECT COSTS - SNCR		
	Purchased Equipment Costs	
	Equipment Cost (EC)	1,081,241
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**1,081,241**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR		**1,081,241**
INDIRECT INSTALLATION COSTS - SNCR		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	32,437
TOTAL INDIRECT COSTS, IC - SNCR		**32,437**
TOTAL CAPITAL INVESTMENT (TCI) - LNB		**9,598,957**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR		**1,113,678**
TOTAL CAPITAL INVESTMENT (TCI)		**10,712,635**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		294,597
		294,597
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		11,152
Electricity Cost		0.8
Subtotal - Utilities		**11,153**
TOTAL ANNUAL DIRECT COSTS[a]		**305,750**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**305,750**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		10,712,635
TOTAL ANNUAL CAPITAL REQUIREMENT		**2,715,545**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**3,021,296**

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Source	**Unit 210-H101**	
Control	**ULNB**	
Rated Heat Input	**192.0**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**74.85**	**tpy**
Current Emission Rate	**0.089**	**lb/MMBtu**
Control Efficiency	**66%**	
Heater Capacity	**202.6**	**GJ/hr**
Burner Heat Release Rate	**40.4**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	1,133,816
Instrumentation (10% of EC)	113,382
Sales taxes (5% of EC)	56,691
Freight (8% of EC)	90,705
Subtotal - Purchased Equipment Costs (PEC)	**1,394,593**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**1,394,593**
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	69,730
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	139,459
Start-up (1% of PEC)	13,946
Performance Test (1% of PEC)	13,946
Contingency (3% of PEC)	41,838
TOTAL INDIRECT COSTS, IC	**278,919**
TOTAL CAPITAL INVESTMENT (TCI)	**1,673,512**

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COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			46,022
			46,022
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
None			
Subtotal - Utilities			**0.0**
TOTAL ANNUAL DIRECT COSTS[a]			**46,022**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**46,022**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			1,673,512
TOTAL ANNUAL CAPITAL REQUIREMENT			**424,218**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**470,240**

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Source	**Unit 210-H101**	
Control	**SNCR**	
Rated Heat Input	**192.0**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**74.85**	**tpy**
Current Emission Rate	**0.089**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**202.6**	**GJ/hr**
Burner Heat Release Rate	**40.4**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	1,081,241
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**1,081,241**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**1,081,241**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	32,437
TOTAL INDIRECT COSTS, IC		**32,437**
TOTAL CAPITAL INVESTMENT (TCI)		**1,113,678**

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COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			30,626
			30,626
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			11,152
Electricity Cost			0.8
Subtotal - Utilities			**11,153**
TOTAL ANNUAL DIRECT COSTS[a]			**41,779**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**41,779**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			1,113,678
TOTAL ANNUAL CAPITAL REQUIREMENT			**282,306**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**324,085**

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 210-H201 RACT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	254	0.03	33.4	96%	1.3	32.0	NA	NA	NA	NA
SCR	254	0.03	33.4	85%	5.0	28.4	NA	NA	NA	NA
LNB & SNCR	254	0.03	33.4	70%	10.0	23.4	13,474,367	375,519	3,791,135	162,271
LNB & FGR	254	0.03	33.4	55%	15.0	18.4	NA	NA	NA	NA
SNCR	254	0.03	33.4	40%	20.0	13.4	1,317,284	41,199	375,117	28,098
ULNB	254	0.03	33.4	0%	33.4	0.0	NA	NA	NA	NA
Calculation			= A * B * 8760 / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Technical Infeasibilities:
SCR would not physically fit the plot space and there is not adequate pressure to overcome the SCR pressure drop; therefore, SCR is infeasible.
FGR installation would require the installation of mechanical draft burners, which is a major re-design of the unit; therefore FGR is infeasible.
Notes:
[1] ULNB is already installed on the Unit 210-H201 heater.
[2] See "RACT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

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NOx RACT Control Cost Effectiveness

Source	**Unit 210-H201**	
Control	**LNB & SNCR**	
Rated Heat Input	**254.0**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**33.38**	**tpy**
Current Emission Rate	**0.030**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**268.0**	**GJ/hr**
Burner Heat Release Rate	**39.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	8,236,506
Instrumentation (10% of EC)	823,651
Sales taxes (5% of EC)	411,825
Freight (8% of EC)	658,920
Subtotal - Purchased Equipment Costs (PEC)	**10,130,902**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**10,130,902**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	506,545
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	1,013,090
Start-up (1% of PEC)	101,309
Performance Test (1% of PEC)	101,309
Contingency (3% of PEC)	303,927
TOTAL INDIRECT COSTS, IC - LNB	**2,026,180**
DIRECT COSTS - SNCR	
Purchased Equipment Costs	
Equipment Cost (EC)	1,278,916
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**1,278,916**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR	**1,278,916**
INDIRECT INSTALLATION COSTS - SNCR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	38,367
TOTAL INDIRECT COSTS, IC - SNCR	**38,367**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**12,157,083**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR	**1,317,284**
TOTAL CAPITAL INVESTMENT (TCI)	**13,474,367**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		370,545
		370,545
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,973
Electricity Cost		0.4
Subtotal - Utilities		**4,973**
TOTAL ANNUAL DIRECT COSTS[a]		**375,519**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**375,519**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		13,474,367
TOTAL ANNUAL CAPITAL REQUIREMENT		**3,415,616**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**3,791,135**

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Source	**Unit 210-H201**	
Control	**SNCR**	
Rated Heat Input	**254.0**	**MMBtu/hr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**33.38**	**tpy**
Current Emission Rate	**0.030**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**268.0**	**GJ/hr**
Burner Heat Release Rate	**39.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	1,278,916
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**1,278,916**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**1,278,916**
INDIRECT INSTALLATION COSTS	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	38,367
TOTAL INDIRECT COSTS, IC	**38,367**
TOTAL CAPITAL INVESTMENT (TCI)	**1,317,284**

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Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		36,225
		36,225
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,973
Electricity Cost		0.4
Subtotal - Utilities		**4,973**
TOTAL ANNUAL DIRECT COSTS[a]		**41,199**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**41,199**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		1,317,284
TOTAL ANNUAL CAPITAL REQUIREMENT		**333,918**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**375,117**

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 866-12H1 RACT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	61.2	0.113	30.3	96%	1.2	29.1	3,518,199	121,208	1,013,036	34,831
SCR	61.2	0.113	30.3	85%	4.5	25.7	2,984,767	106,538	863,147	33,524
ULNB	61.2	0.113	30.3	73%	8.0	22.2	533,432	14,669	149,889	6,737
LNB & SNCR	61.2	0.113	30.3	70%	9.1	21.2	838,966	27,585	240,255	11,331
LNB & FGR	61.2	0.113	30.3	55%	13.6	16.7	503,525	21,628	149,267	8,960
SNCR	61.2	0.113	30.3	40%	18.2	12.1	560,828	19,936	162,101	13,379
Calculation			= A * B * 8760 / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Notes:

[1] Unit 866-12H1 is projected to be above PADEP presumptive RACT firing limits and assumed NO_x emission rate limit of 0.113 lb/MMBtu is used.

[2] See "RACT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

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Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 866-12H1**	
Control	**ULNB & SCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**30.29**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**96%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS - ULNB		
	Purchased Equipment Costs	
	Equipment Cost (EC)	361,404
	Instrumentation (10% of EC)	36,140
	Sales taxes (5% of EC)	18,070
	Freight (8% of EC)	28,912
	Subtotal - Purchased Equipment Costs (PEC)	**444,527**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - ULNB		**444,527**
INDIRECT INSTALLATION COSTS - ULNB		
	Engineering Costs (5% of PEC)	22,226
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	44,453
	Start-up (1% of PEC)	4,445
	Performance Test (1% of PEC)	4,445
	Contingency (3% of PEC)	13,336
TOTAL INDIRECT COSTS, IC - ULNB		**88,905**
DIRECT COSTS - SCR		
	Purchased Equipment Costs	
	Equipment Cost (EC)	2,897,832
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**2,897,832**
	Direct Installation Costs	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SCR		**2,897,832**
INDIRECT INSTALLATION COSTS - SCR		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	86,935
TOTAL INDIRECT COSTS, IC - SCR		**86,935**
TOTAL CAPITAL INVESTMENT (TCI) - ULNB		**533,432**
TOTAL CAPITAL INVESTMENT (TCI) - SCR		**2,984,767**
TOTAL CAPITAL INVESTMENT (TCI)		**3,518,199**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		96,750
		96,750
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,513
Catalyst Replacement Cost		19,943
Electricity Cost		0.3
Subtotal - Utilities		**24,457**
TOTAL ANNUAL DIRECT COSTS"		**121,208**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**121,208**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		3,518,199
TOTAL ANNUAL CAPITAL REQUIREMENT		**891,828**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**1,013,036**

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NOx RACT Control Cost Effectiveness

Source	**Unit 866-12H1**	
Control	**SCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**30.29**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	2,897,832
	Instrumentation (Included in above costs)	- - -
	Sales taxes (Included in above costs)	- - -
	Freight (Included in above costs)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**2,897,832**
	Direct Installation Costs	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**2,897,832**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (Included in above costs)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (Included in above costs)	- - -
	Start-up (Included in above costs)	- - -
	Performance Test (Included in above costs)	- - -
	Contingency (3% of PEC)	86,935
TOTAL INDIRECT COSTS, IC		**86,935**
TOTAL CAPITAL INVESTMENT (TCI)		**2,984,767**

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Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			82,081
			82,081
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,513
Catalyst Replacement Cost			19,943
Electricity Cost			0.3
Subtotal - Utilities			**24,457**
TOTAL ANNUAL DIRECT COSTS[a]			**106,538**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**106,538**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			2,984,767
TOTAL ANNUAL CAPITAL REQUIREMENT			**756,608**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**863,147**

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NOx RACT Control Cost Effectiveness

Source	**Unit 866-12H1**	
Control	**ULNB**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**30.29**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**73%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	361,404
Instrumentation (10% of EC)	36,140
Sales taxes (5% of EC)	18,070
Freight (8% of EC)	28,912
Subtotal - Purchased Equipment Costs (PEC)	**444,527**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**444,527**
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	22,226
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	44,453
Start-up (1% of PEC)	4,445
Performance Test (1% of PEC)	4,445
Contingency (3% of PEC)	13,336
TOTAL INDIRECT COSTS, IC	**88,905**
TOTAL CAPITAL INVESTMENT (TCI)	**533,432**

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COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			14,669
			14,669
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
None			
Subtotal - Utilities			**0.0**
TOTAL ANNUAL DIRECT COSTS[a]			**14,669**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**14,669**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			533,432
TOTAL ANNUAL CAPITAL REQUIREMENT			**135,220**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**149,889**

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Source	**Unit 866-12H1**	
Control	**LNB & SNCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**30.29**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	188,440
Instrumentation (10% of EC)	18,844
Sales taxes (5% of EC)	9,422
Freight (8% of EC)	15,075
Subtotal - Purchased Equipment Costs (PEC)	**231,781**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**231,781**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	11,589
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	23,178
Start-up (1% of PEC)	2,318
Performance Test (1% of PEC)	2,318
Contingency (3% of PEC)	6,953
TOTAL INDIRECT COSTS, IC - LNB	**46,356**
DIRECT COSTS - SNCR	
Purchased Equipment Costs	
Equipment Cost (EC)	544,494
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**544,494**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR	**544,494**
INDIRECT INSTALLATION COSTS - SNCR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	16,335
TOTAL INDIRECT COSTS, IC - SNCR	**16,335**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**278,137**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR	**560,828**
TOTAL CAPITAL INVESTMENT (TCI)	**838,966**

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NOx RACT Control Cost Effectiveness

COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		23,072
		23,072
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,513
Electricity Cost		0.3
Subtotal - Utilities		**4,514**
TOTAL ANNUAL DIRECT COSTS[a]		**27,585**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**27,585**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		838,966
TOTAL ANNUAL CAPITAL REQUIREMENT		**212,669**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**240,255**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

Source	**Unit 866-12H1**	
Control	**LNB & FGR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**30.29**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**55%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	188,440
Instrumentation (10% of EC)	18,844
Sales taxes (5% of EC)	9,422
Freight (8% of EC)	15,075
Subtotal - Purchased Equipment Costs (PEC)	**231,781**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**231,781**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	11,589
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	23,178
Start-up (1% of PEC)	2,318
Performance Test (1% of PEC)	2,318
Contingency (3% of PEC)	6,953
TOTAL INDIRECT COSTS, IC - LNB	**46,356**
DIRECT COSTS - FGR	
Purchased Equipment Costs	
Equipment Cost (EC)	218,823
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**218,823**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - FGR	**218,823**
INDIRECT INSTALLATION COSTS - FGR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	6,565
TOTAL INDIRECT COSTS, IC - FGR	**6,565**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**278,137**
TOTAL CAPITAL INVESTMENT (TCI) - FGR	**225,388**
TOTAL CAPITAL INVESTMENT (TCI)	**503,525**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		13,847
		13,847
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Electricity Cost		7,781
Subtotal - Utilities		**7,781**
TOTAL ANNUAL DIRECT COSTS[a]		**21,628**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**21,628**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		503,525
TOTAL ANNUAL CAPITAL REQUIREMENT		**127,639**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**149,267**

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Source	**Unit 866-12H1**	
Control	**SNCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**30.29**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	544,494
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**544,494**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**544,494**
INDIRECT INSTALLATION COSTS	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	16,335
TOTAL INDIRECT COSTS, IC	**16,335**
TOTAL CAPITAL INVESTMENT (TCI)	**560,828**

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Heater Firing Rate Increase Plan Approval
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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		15,423
		15,423
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,513
Electricity Cost		0.3
Subtotal - Utilities		**4,514**
TOTAL ANNUAL DIRECT COSTS[a]		**19,936**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**19,936**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		560,828
TOTAL ANNUAL CAPITAL REQUIREMENT		**142,164**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**162,101**

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 868-8H101 RACT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	60	0.113	29.7	96%	1.2	28.5	3,472,395	119,468	999,686	35,060
SCR	60	0.113	29.7	85%	4.5	25.2	2,949,422	105,087	852,736	33,782
ULNB	60	0.113	29.7	73%	7.9	21.8	522,973	14,382	146,950	6,737
LNB & SNCR	60	0.113	29.7	70%	8.9	20.8	1,057,946	33,519	301,697	14,513
LNB & FGR	60	0.113	29.7	55%	13.4	16.3	726,468	27,607	211,759	12,965
SNCR	60	0.113	29.7	40%	17.8	11.9	554,204	19,666	160,151	13,482
Calculation			= A * B * 8760 / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Notes:
[1] Unit 868-8H101 is projected to be above PADEP presumptive RACT firing limits and assumed NO_x emission rate limit of 0.113 lb/MMBtu is used.
[2] See "RACT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

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Source	**Unit 868-8H101**	
Control	**ULNB & SCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**29.70**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**96%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - ULNB	
Purchased Equipment Costs	
Equipment Cost (EC)	354,317
Instrumentation (10% of EC)	35,432
Sales taxes (5% of EC)	17,716
Freight (8% of EC)	28,345
Subtotal - Purchased Equipment Costs (PEC)	**435,810**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - ULNB	**435,810**
INDIRECT INSTALLATION COSTS - ULNB	
Engineering Costs (5% of PEC)	21,791
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	43,581
Start-up (1% of PEC)	4,358
Performance Test (1% of PEC)	4,358
Contingency (3% of PEC)	13,074
TOTAL INDIRECT COSTS, IC - ULNB	**87,162**
DIRECT COSTS - SCR	
Purchased Equipment Costs	
Equipment Cost (EC)	2,863,517
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,863,517**
Direct Installation Costs	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SCR	**2,863,517**
INDIRECT INSTALLATION COSTS - SCR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	85,906
TOTAL INDIRECT COSTS, IC - SCR	**85,906**
TOTAL CAPITAL INVESTMENT (TCI) - ULNB	**522,973**
TOTAL CAPITAL INVESTMENT (TCI) - SCR	**2,949,422**
TOTAL CAPITAL INVESTMENT (TCI)	**3,472,395**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		95,491
		95,491
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,425
Catalyst Replacement Cost		19,552
Electricity Cost		0.3
Subtotal - Utilities		**23,978**
TOTAL ANNUAL DIRECT COSTS"		**119,468**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**119,468**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		3,472,395
TOTAL ANNUAL CAPITAL REQUIREMENT		**880,217**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**999,686**

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Source	**Unit 868-8H101**	
Control	**SCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**29.70**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	2,863,517
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,863,517**
Direct Installation Costs	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**2,863,517**
INDIRECT INSTALLATION COSTS	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	85,906
TOTAL INDIRECT COSTS, IC	**85,906**
TOTAL CAPITAL INVESTMENT (TCI)	**2,949,422**

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COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			81,109
			81,109
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,425
Catalyst Replacement Cost			19,552
Electricity Cost			0.3
Subtotal - Utilities			**23,978**
TOTAL ANNUAL DIRECT COSTS[a]			**105,087**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**105,087**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			2,949,422
TOTAL ANNUAL CAPITAL REQUIREMENT			**747,649**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**852,736**

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Source	**Unit 868-8H101**	
Control	**ULNB**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**29.70**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**73%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	354,317
	Instrumentation (10% of EC)	35,432
	Sales taxes (5% of EC)	17,716
	Freight (8% of EC)	28,345
	Subtotal - Purchased Equipment Costs (PEC)	**435,810**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**435,810**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	21,791
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	43,581
	Start-up (1% of PEC)	4,358
	Performance Test (1% of PEC)	4,358
	Contingency (3% of PEC)	13,074
TOTAL INDIRECT COSTS, IC		**87,162**
TOTAL CAPITAL INVESTMENT (TCI)		**522,973**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		14,382
		14,382
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
None		
Subtotal - Utilities		**0.0**
TOTAL ANNUAL DIRECT COSTS[a]		**14,382**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**14,382**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		522,973
TOTAL ANNUAL CAPITAL REQUIREMENT		**132,568**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**146,950**

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Source	**Unit 868-8H101**	
Control	**LNB & SNCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**29.70**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	341,289
Instrumentation (10% of EC)	34,129
Sales taxes (5% of EC)	17,064
Freight (8% of EC)	27,303
Subtotal - Purchased Equipment Costs (PEC)	**419,785**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**419,785**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	20,989
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	41,979
Start-up (1% of PEC)	4,198
Performance Test (1% of PEC)	4,198
Contingency (3% of PEC)	12,594
TOTAL INDIRECT COSTS, IC - LNB	**83,957**
DIRECT COSTS - SNCR	
Purchased Equipment Costs	
Equipment Cost (EC)	538,062
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**538,062**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR	**538,062**
INDIRECT INSTALLATION COSTS - SNCR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	16,142
TOTAL INDIRECT COSTS, IC - SNCR	**16,142**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**503,742**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR	**554,204**
TOTAL CAPITAL INVESTMENT (TCI)	**1,057,946**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		29,094
		29,094
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,425
Electricity Cost		0.3
Subtotal - Utilities		**4,425**
TOTAL ANNUAL DIRECT COSTS[a]		**33,519**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**33,519**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		1,057,946
TOTAL ANNUAL CAPITAL REQUIREMENT		**268,179**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**301,697**

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Source	**Unit 868-8H101**	
Control	**LNB & FGR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**29.70**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**55%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	341,289
Instrumentation (10% of EC)	34,129
Sales taxes (5% of EC)	17,064
Freight (8% of EC)	27,303
Subtotal - Purchased Equipment Costs (PEC)	**419,785**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**419,785**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	20,989
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	41,979
Start-up (1% of PEC)	4,198
Performance Test (1% of PEC)	4,198
Contingency (3% of PEC)	12,594
TOTAL INDIRECT COSTS, IC - LNB	**83,957**
DIRECT COSTS - FGR	
Purchased Equipment Costs	
Equipment Cost (EC)	216,239
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**216,239**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - FGR	**216,239**
INDIRECT INSTALLATION COSTS - FGR	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	6,487
TOTAL INDIRECT COSTS, IC - FGR	**6,487**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**503,742**
TOTAL CAPITAL INVESTMENT (TCI) - FGR	**222,726**
TOTAL CAPITAL INVESTMENT (TCI)	**726,468**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		19,978
		19,978
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Electricity Cost		7,629
Subtotal - Utilities		**7,629**
TOTAL ANNUAL DIRECT COSTS[a]		**27,607**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**27,607**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		726,468
TOTAL ANNUAL CAPITAL REQUIREMENT		**184,152**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**211,759**

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Source	**Unit 868-8H101**	
Control	**SNCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**29.70**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	538,062
Instrumentation (Included in above costs)	- - -
Sales taxes (Included in above costs)	- - -
Freight (Included in above costs)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**538,062**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**538,062**
INDIRECT INSTALLATION COSTS	
Engineering Costs (Included in above costs)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (Included in above costs)	- - -
Start-up (Included in above costs)	- - -
Performance Test (Included in above costs)	- - -
Contingency (3% of PEC)	16,142
TOTAL INDIRECT COSTS, IC	**16,142**
TOTAL CAPITAL INVESTMENT (TCI)	**554,204**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx RACT Control Cost Effectiveness

COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			15,241
			15,241
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,425
Electricity Cost			0.3
Subtotal - Utilities			**4,425**
TOTAL ANNUAL DIRECT COSTS[a]			**19,666**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**19,666**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			554,204
TOTAL ANNUAL CAPITAL REQUIREMENT			**140,485**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**160,151**

Attachment B
AMS Plan Approval Application Forms

CITY OF PHILADELPHIA
DEPARTMENT OF PUBLIC HEALTH
PUBLIC HEALTH SERVICES
AIR MANAGEMENT SERVICES

Air Management Services
321 University Avenue
Philadelphia PA 19104-4543
Phone: (215) 685-7572
FAX: (215) 685-7593

APPLICATION FOR PLAN APPROVAL TO CONSTRUCT, MODIFY OR REACTIVATE AN AIR CONTAMINATION SOURCE AND/OR AIR CLEANING DEVICE

(Prepare all information completely in print or type in triplicate)

SECTION A - APPLICATION INFORMATION

Location of source (Street Address) 3144 Passyunk Avenue	Facility Name PES Philadelphia Refinery	
Owner Philadelphia Energy Solutions Refining & Marketing, LLC		Tax ID No. 61-1689574
Mailing Address 3144 Passyunk Avenue, Philadelphia, PA 19145	Telephone No. (215) 339-2074	Fax No. (215) 339-2657
Contact Person Charles D. Barksdale	Title Manager, Environmental Department	
Mailing Address 3144 Passyunk Avenue, Philadelphia, PA 19145	Telephone No. (215) 339-2074	Fax No (215) 339-2657

SECTION B - DESCRIPTION OF ACTIVITY

Application type	SIC Code	Completion Date
☐New source ☐Modification ☐Replacement ☐Reactivation ☐Air cleaning device ☒Other	2911	On Approval

☐ NSPS ☐ NESHAP ☐ Case by Case MACT ☐ NSR ☐ PSD

Does Facility submit Compliance Review Form biannually ? ☒ Yes ☐ No
If No attach Air Pollution Control Act Compliance Review Form with this application.

Source Description: The Sunoco Philadelphia Refinery proposes to marginally increase the firing limitations of seven process heaters and to raise refinery crude feed and product rates by proportionate amounts. No physical modifications are required to either process units or monitoring systems. Emissions increases will be netted to insignificant levels by the application of coincident ERC's from shutdown units at the Sunoco Marcus Hook, Pa Refinery

SECTION C - PERMIT COORDINATION (ONLY REQUIRED FOR LAND DEVELOPMENT)

Question	YES	NO
1. Will the project involve construction activity that disturbs five or more acres of land?		X
2. Will the project involve discharge of industrial wastewater or stormwater to a dry swale, surface water, ground water or an existing sanitary sewer system?		X
3. Will the project involve the construction and operation of industrial waste treatment facility?		X
4. Is onsite sewage disposal proposed for your project?		X
5. Will the project involve construction of sewage treatment facilities, sanitary sewer, or sewage pumping station?		X
6. Is a stormwater collection and discharge system proposed for this project?		X
7. Will any work associated with this project take place in or near a stream, waterway, or wetland?		X
8. Does the project involve dredging or construction of any dam, pier, bridge or outfall pipe?		X
9. Will any solid waste or liquid wastes be generated as a result of the project?		X
10. Is a State Park located within two miles from your project?		X

SECTION D – CERTIFICATION

I certify that I have the authority to submit this Permit Application on behalf of the applicant named herein and that the information provided in this application is true and correct to the best of my knowledge and information.

Signature NThaver Date 9/6/13 Address 3144 Passyunk Avenue, Philadelphia, PA 19145

Name & Title Nithia Thaver, General Manager Phone (215) 339-7414 Fax (215) 339-2657

SECTION E - OFFICIAL USE ONLY

Application No.	Plant ID	Health District	Census Tract	Fee	Date Received

Approved by	Date	Conformance by	Date

SECTION F 1 - GENERAL SOURCE INFORMATION

1. SOURCE						2. NORMAL PROCESS OPERATING SCHEDULE						
	A. Type Source (Describe)	B. Manufacturer of Source	C. Model No.	D. Rated Capacity (Specify units)	E. Type of Materials Processed	A. Amount Processed/yr. (Specify units)	B. Average hr/day	C. Total hr/yr	D. % Throughput/Quarter			
									1st	2nd	3rd	4th
1	**Target heaters**											
	See Attached Report for											
	Proposed Heater Firing											
	Changes											

3. ESTIMATED FUEL USAGE (Specify Units)							4. ANNUAL FUEL USAGE						
A. Used in Unit	B. Type Fuel	C. Average Hourly Rate	D. Maximum Hourly Rate	E. Percent Sulfur	F. Percent Ash	G. Heating Value	A. Annual Amounts	B. Average hr/day	C. Total hr/yr	D. % Throughput/Quarter			
										1st	2nd	3rd	4th
	See Attached Report for												
	Proposed Fired Htr. Duty												
	Changes												

5. IMPORTANT: **Attach on a separate sheet a flow diagram of process giving all (gaseous, liquid, and solid) flow rates. Also list raw materials charged to process equipment and the amounts charged (tons/hour, etc.) at rated capacity (give maximum, minimum and average charges describing fully expected variations in production rates). Indicate (on diagram) all points where contaminants are controlled (location of water sprays, hoods or other pickup points, etc.).**

SECTION F 1 - GENERAL SOURCE INFORMATION, CONTINUED
6. Describe process equipments in detail. **See Attached Report Sections**
7. Describe fully the methods used to monitor and record all operating conditions that may affect the emission of air contaminants. Provide detailed information to show that these methods provided are adequate. **No New Monitoring Equipment is Proposed or Required**
8. Describe modifications to process equipments in detail. **See Attached Report Sections**
9. Attach any and all additional information necessary to adequately describe the process equipment and to perform a thorough evaluation of the extent and nature of its emissions. **See Attached Report that includes a BAT/RACT analysis**

- PROVIDE EQUIPMENT INFORMATION ON THIS PAGE IF SOURCES DO NOT BELONG TO SPECIAL CATEGORIES IN F2 TO F8, OTHERWISE REMOVE THIS PAGE FROM THIS APPLICATION.
- IF THERE ARE MORE EQUIPMENT, COPY THIS PAGE AND FILL IN THE INFORMATION AS INDICATED

SECTION F 2 - COMBUSTION UNITS INFORMATION		
1. COMBUSTION UNITS **H101; H201; 11H1; 11H2; 12H1; 8H101; B101 - See Discussion Sections**		
A. Manufacturer **NA**	B. Model No. **NA**	C. Unit No. **NA**
D. Rated heat input (Btu/hr) **NA**	E. Peak heat input (Btu/hr) **NA**	F. Use **NA**
G. Method firing ☐ Pulverized ☐ Spreader Stoker ☐ Cyclone ☐ Tangential ☐ Normal ☐ Fluidized bed ☐ Other ____________		

2. FUEL REQUIREMENTS

TYPE	*QUANTITY HOURLY*	*QUANTITY ANNUALLY*	*SULFUR*	*ASH*	*BTU CONTENT*
OIL NUMBER **NA**	**NA**	**NA**	**NA**	**NA**	**NA**
OTHER **NA**	**NA**	**NA**	**NA**	**NA**	**NA**

3. COMBUSTION AIDS, CONTROLS, AND MONITORS -- **(No New Equipment)**

☐ A. Overfire jets	Type	Number	Height above grate
☐ B. Draft controls	Type	Type	
☐ C. Oil preheat			
☐ D. Soot cleaning	Temperature (° F)	Frequency	
☐ E. Stack sprays	Method		
☐ F. Opacity monitoring device		Method	Cost
☐ G. Sulfur oxides monitoring device	Type	Method	Cost
☒ H. Nitrogen oxides monitoring device	Type	Method	Cost
☒ I. Fuel metering and/or recording devices	Type	Method	Cost
☐ J. Atomization interlocking device	Type	Method	Cost
☐ K. Collected flyash reentrainment preventative device	Type		
☐ L. Modulating controls ☐ Step ☐ Automatic			

4. ☐ Flyash reinjection. (Describe operation)
N/A

5. Describe method of supplying make up air to the furnace room.
N/A

- USE THIS PAGE FOR COMBUSTION SOURCE, OTHERWISE REMOVE THIS PAGE FROM THIS APPLICATION.
- IF THERE ARE MORE THAN ONE UNIT, COPY THIS PAGE AND FILL IN THE INFORMATION AS INDICATED

SECTION F 2 - COMBUSTION UNITS INFORMATION, CONTINUED

6. OPERATING SCHEDULE

__ **NA** ______________ hours/day ______ **NA** ___________ days/week __ **NA** _______________ weeks/year

7. SEASONAL PERIODS (MONTHS) **N/A**

Operating using primary fuel ___________________ Operating using secondary fuel ___________________

___________________ to ___________________ ___________________ to ___________________

Non-operating

___________________ to ___________________

8. If heat input is in excess of 250 x 10^6 Btu/hr., describe fully the methods used to record the following: rate of fuel burned; heating value, sulfur and ash content of fuels; smoke, sulfur oxides and nitrogen oxides emissions; and if electric generating plant, the average electrical output and the minimum and maximum hourly generation rate.

PES will continue to monitor, record, and report with applicable requirements found in the Philadelphia Refinery's existing Title V permit and the Consent Decree

9. Describe modifications to boiler in detail.

See Attached Report Sections

10. Type and method of disposal of all waste materials generated by this boiler.
(Is a Solid Waste Disposal Permit needed? ☐ Yes ☒ No)

11. Briefly describe the method of handling the waste water from this boiler and its associated air pollution control equipment.
(Is a Water quality Management Permit needed? ☐ Yes ☒ No)

12. Attach any and all additional information necessary to perform a thorough evaluation of this boiler.

See Attached Report Sections

- USE THIS PAGE FOR COMBUSTION SOURCE, OTHERWISE REMOVE THIS PAGE FROM THIS APPLICATION.
- IF THERE ARE MORE THAN ONE UNIT, COPY THIS PAGE AND FILL IN THE INFORMATION AS INDICATED

SECTION G - FLUE AND AIR CONTAMINANT EMISSION INFORMATION

1. STACK AND EXHAUSTER

This project does not involve any changes to existing stacks or emission points.

A. Outlet volume of exhaust gases

_______________ CFM @_______ °F __________ % Moisture

B, Exhauster (attach fan curves)

__________ in w.g. _______________ HP @ _________________ RPM

C . Stack height above grade (ft) __________

Grade elevation (ft) __________

Distance from discharge to nearest property line(ft) _________

D Stack diameter (ft) or Outlet duct area (sq. ft.)

E Weather Cap

☐ YES ☐ NO

F. Indicate on an attached sheet the location of sampling ports with respect to exhaust fan, breeching, etc. Give all necessary dimensions.

2 POTENTIAL PROCESS EMISSIONS (OUTLET FROM PROCESS, BEFORE ANY CONTROL EQUIPMENT)

See Attached Report Sections

A. Particulate loading (lbs/hr or gr/DSCF)

B. Specific gravity of particulate (not bulk density)

C . Attached particle size distribution information

D. Specify gaseous contaminants and concentration

Contaminant		Concentration			VOC Contaminants	Concentration	
(1)	SO_x	________ ppm (Vol.)	________ lbs/hr	(4)	__________	________ ppm (Vol.)	________ lbs/hr
(2)	NO_x	________ ppm (Vol.)	________ lbs/hr	(5)	__________	________ ppm (Vol.)	________ lbs/hr
(3)	CO	________ ppm (Vol.)	________ lbs/hr	(6)	__________	________ ppm (Vol.)	________ lbs/hr

E. Does process vent through the control device ? ☐ YES ☐ NO

- If YES continue and fill out the appropriate SECTION H - CONTROL EQUIPMENT
- If NO skip to SECTION I - MISCELLANEOUS INFORMATION

F. Can the control equipment be bypassed: (If Yes, explain) ☐ YES ☐ NO

3. ATMOSPHERIC EMISSIONS

A. Particulate matter emissions (tons per year)

See Attached Report Sections

B. Gaseous contaminant emissions

Contaminants	Concentration		VOC Contaminants	Concentration
(1)	_______ (tpy)	(4)___	______	_____ (tpy)
(2)	______ (tpy)	(5)	_________	_____ (tpy)
(3)	_____ (tpy)	(6)	_____________	_________ (tpy)

See Attached Report Sections

SECTION H - CONTROL EQUIPMENT, CONTINUED

12. COSTS – **See Attached Report Sections**

A. List costs associated with control equipment. (List individual controls separately)

Control Equipment Cost:
Direct Cost:

Indirect Cost:

B. Estimated annual operating costs of control equipment only.

13. Describe modifications to control equipment in detail.

N/A

14. Describe in detail the method of dust removal from the air cleaning and methods of controlling fugitive emissions from dust removal, handling and disposal.

N/A

15. Does air cleaning device employ hopper heaters, hopper vibrators or hopper level detectors? If so, describe.

N/A

16. Attach manufacturer's performance guarantees and/or warranties for each of the major components of the control system (or complete system).

17. Attach the maintenance schedule for the control equipment and any part of the process equipment that if in disrepair would increase the air contaminant emissions. Periodic maintenance reports are to be submitted to the Department.

Maintenance will continue to be be provided as per the manufacturer's recommendations and the Title V Permit.

18. Attach any and all additional information necessary to thoroughly evaluate the control equipment.

See Attached Report Sections

SECTION I - MISCELLANEOUS INFORMATION

1. Specify monitoring and recording devices will be used for monitoring and recording of the emission of air contaminants. Provide detailed information to show that the facilities provided are adequate. Include cost and maintenance information.

☐ Opacity monitoring system	☐ SOx monitoring system	☒ NOx monitoring system
☐ CO monitoring system	☐ CO2 monitoring system	☒ Oxygen monitoring system
☐ HCL monitoring system	☐ TRS monitoring system	☐ H2S monitoring system
☐ Temperature monitoring system	☐ Stack flow monitoring system	☐ Other __________

If checked, provide manufacturer's name, model no. and pertinent technical specifications.

NO CHANGES PROPOSED FROM EXISTING MONITORING, AS OUTLINED IN EXISTING TITLE V PERMIT.

- PROVIDE CONTROL EQUIPMENT INFORMATION ON THIS PAGE IF IT PERTAINS TO THIS APPLICATION, OTHERWISE REMOVE THIS PAGE FROM THE APPLICATION.
- IF THERE ARE MORE OF THE SAME TYPE OF CONTROL EQUIPMENT, COPY THAT PAGE AND FILL IN THE INFORMATION AS INDICATED.
- CONTROL EQUIPMENT CAN BE FOUND FROM A MANUFACTURER CATALOGUE OR VENDORS.

2. Attach Air Pollution Episode Strategy (if applicable)

NA

3. If the source is subject to 25 Pa. Code Subchapter E, New Source Review requirements,

    a. Demonstrate the availability of emission offset (if applicable)

    b. Provide an analysis of alternate sites, sizes, production processes and environmental control techniques demonstrating that the benefits of the proposed source outweigh the environmental and social costs.

CO Dispersion modeling is required for PSD purposes. NSR for nonattainment pollutants is not applicable. See the attached Report Sections.

4. Attach calculations and any additional information necessary to thoroughly evaluate compliance with all the applicable requirements of Article III of the rules and regulations of Philadelphia Air Management, Pennsylvania Department of Environmental Protection and those requirements promulgated by the Administrator of the United States Environmental Protection Agency pursuant to the provisions of the Clean Air Act.

See Attached Report Sections

- PROVIDE CONTROL EQUIPMENT INFORMATION ON THIS PAGE IF IT PERTAINS TO THIS APPLICATION, OTHERWISE REMOVE THIS PAGE FROM THE APPLICATION.
- IF THERE ARE MORE OF THE SAME TYPE OF CONTROL EQUIPMENT, COPY THAT PAGE AND FILL IN THE INFORMATION AS INDICATED.
- CONTROL EQUIPMENT CAN BE FOUND FROM A MANUFACTURER CATALOGUE OR VENDORS.

Attachment C
Compliance Review History

Compliance History Review

The Pa. Code 25 Section 127.12 requires either a completed compliance review form, or reference to the most recently submitted forms for facilities submitting a compliance review form on a periodic basis. PES files compliance review semi-annually per 127.12a(j).
The latest form covering the Philadelphia Refinery was sent to the offices of Philadelphia Air Management Services in July of 2013.

PHILADELPHIA
ENERGY SOLUTIONS

Philadelphia Refinery

Philadelphia Energy Solutions
Refining and Marketing LLC
3144 Passyunk Avenue
Philadelphia, PA 19145-5299
215-339-2000

Certified Mail: 7002 0460 0003 1936 6809

July 8, 2013

Department of Public Health
Air Management Services
321 University Avenue
Philadelphia, PA 19104

Re: Philadelphia Energy Solutions Refining and Marketing LLC
Title V Permit V95-038 (Philadelphia Refinery)
Title V Permit V95-039 (Schuylkill River Tank Farm)
Pennsylvania Air Pollution Control Act Compliance History Semi-Annual Submission

Dear Air Quality Program Manager:

Pursuant to 25 Pa. Code 127.412(j), Philadelphia Energy Solutions Refining and Marketing LLC (PES) hereby submits its semi-annual Pennsylvania Air Pollution Control Act Compliance History Form. As provided in 127.412(j), it is PES's ongoing intention to update this submission every six (6) months as opposed to submitting updates with each permit application that may be submitted throughout the year. The short term temporary diesel permits are not included in this submittal, if needed, they can be provided.

Should you have any questions or comments pertaining to this notification, contact me at (215) 339-2074.

Sincerely,

Charles D. Barksdale
Environmental Manager

CDB/pm

Copies:

Certified Mail: 7002 0460 0003 1936 6731
Pennsylvania Department of Environmental Protection
Attn: Air Quality Program Manager
2 East Main Street
Norristown, PA 19401

Certified Mail: 7002 0460 0003 1936 6724
Pennsylvania Department of Environmental Protection
Attn: Air Quality Program Manager
909 Elmerton Avenue
Harrisburg, PA 17110-8200

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

AIR POLLUTION CONTROL ACT COMPLIANCE REVIEW FORM

Fully and accurately provide the following information, as specified. Attach additional sheets as necessary.

Type of Compliance Review Form Submittal (check all that apply)

☐ Original Filing
☒ Amended Filing

Date of Last Compliance Review Form Filing: 02/06/2013

Type of Submittal

☐ New Plan Approval
☐ Extension of Plan Approval
☐ Other:
☐ New Operating Permit
☐ Change of Ownership
☐ Renewal of Operating Permit
☒ Periodic Submission (@ 6 mos)

SECTION A. GENERAL APPLICATION INFORMATION

Name of Applicant/Permittee/("applicant")
(non-corporations-attach documentation of legal name)

Philadelphia Energy Solutions Refining and Marketing, LLC

Address 3144 Passyunk Ave.
Philadelphia, PA 19145

Telephone 215-339-2000 **Taxpayer ID#** 61-1689574

Permit, Plan Approval or Application ID# N/A

Identify the form of management under which the applicant conducts its business (check appropriate box)

☐ Individual
☐ Municipality
☐ Proprietorship
☐ Public Corporation
☒ Private Corporation
☐ Syndicate
☐ Municipal Authority
☐ Fictitious Name
☐ Partnership
☐ Limited Partnership
☐ Government Agency
☐ Joint Venture
☐ Association
☐ Other Type of Business, specify below:

Describe below the type(s) of business activities performed.

Petroleum Refining operations.

SECTION B. GENERAL INFORMATION REGARDING "APPLICANT"

If applicant is a corporation or a division or other unit of a corporation, provide the names, principal places of business, state of incorporation, and taxpayer ID numbers of all domestic and foreign parent corporations (including the ultimate parent corporation), and all domestic and foreign subsidiary corporations of the ultimate parent corporation with operations in Pennsylvania. Please include all corporate divisions or units, (whether incorporated or unincorporated) and privately held corporations. (A diagram of corporate relationships may be provided to illustrate corporate relationships.) Attach additional sheets as necessary.

Unit Name	Principal Places of Business	State of Incorporation	Taxpayer ID	Relationship to Applicant
Philadelphia Energy Solutions, LLC	Philadelphia	PA	61-1688740	Parent
Philadelphia Energy Solutions Refining & Marketing, LLC	Philadelphia	PA	61-1689574	Applicant

SECTION C. SPECIFIC INFORMATION REGARDING APPLICANT AND ITS "RELATED PARTIES"

Pennsylvania Facilities. List the name and location (mailing address, municipality, county), telephone number, and relationship to applicant (parent, subsidiary or general partner) of applicant and all Related Parties' places of business, and facilities in Pennsylvania. Attach additional sheets as necessary.

Unit Name	Street Address	County and Municipality	Telephone No.	Relationship to Applicant
Philadelphia Refinery Complex	3144 Passyunk Ave., Philadelphia, PA 19145	Philadelphia, Philadelphia	215-339-2000	Applicant
Schuylkill River Tank Farm	3144 Passyunk Ave., Philadelphia, PA 19145	Philadelphia, Philadelphia	215-339-2000	Applicant

Provide the names and business addresses of all general partners of the applicant and parent and subsidiary corporations, if any.

Name	Business Address
None	

List the names and business address of persons with overall management responsibility for the process being permitted (i.e. plant manager).

Name	Business Address
Mr. James A. Keeler General Manager, PES Refinery	3144 Passyunk Ave., Philadelphia, PA 19145

Plan Approvals or Operating Permits. List all plan approvals or operating permits issued by the Department or an approved local air pollution control agency under the APCA to the applicant or related parties that are currently in effect or have been in effect at any time 5 years prior to the date on which this form is notarized. This list shall include the plan approval and operating permit numbers, locations, issuance and expiration dates. Attach additional sheets as necessary.

Air Contamination Source	Plan Approval/ Operating Permit#	Location	Issuance Date	Expiration Date
See Attachment				

Compliance Background. (Note: Copies of specific documents, if applicable, must be made available to the Department upon its request.) List all documented conduct of violations or enforcement actions identified by the Department pursuant to the APCA, regulations, terms and conditions of an operating permit or plan approval or order by applicant or any related party, using the following format grouped by source and location in reverse chronological order. Attach additional sheets as necessary. See the definition of "documented conduct" for further clarification. Unless specifically directed by the Department, deviations which have been previously reported to the Department in writing, relating to monitoring and reporting, need not be reported.

Date	Location	Plan Approval/ Operating Permit#	Nature of Documented Conduct	Type of Department Action	Status: Litigation Existing/Continuing or Corrected/Date	Dollar Amount Penalty
None						$
						$
						$
						$
						$
						$
						$
						$
						$
						$

List all incidents of deviations of the APCA, regulations, terms and conditions of an operating permit or plan approval or order by applicant or any related party, using the following format grouped by source and location in reverse chronological order. This list must include items both currently known and unknown to the Department. Attach additional sheets as necessary. See the definition of "deviations" for further clarification.

Date	Location	Plan Approval/ Operating Permit#	Nature of Deviation	Incident Status: Litigation Existing/Continuing Or Corrected/Date
	Philadelphia Refinery	V95-038 - issued on January 17, 2002.	Deviations are reported pursuant to the requirements in the Title V permit.	
	SRTF	V05-011 - issued on February 24, 2012.	Deviations are reported pursuant to the requirements in the Title V permit.	

CONTINUING OBLIGATION. Applicant is under a continuing obligation to update this form using the Compliance Review Supplemental Form if any additional deviations occur between the date of submission and Department action on the application.

VERIFICATION STATEMENT

Subject to the penalties of Title 18 Pa.C.S. Section 4904 and 35 P.S. Section 4009(b)(2), I verify under penalty of law that I am authorized to make this verification on behalf of the Applicant/Permittee. I further verify that the information contained in this Compliance Review Form is true and complete to the best of my belief formed after reasonable inquiry. I further verify that reasonable procedures are in place to ensure that "documented conduct" and "deviations" as defined in 25 Pa Code Section 121.1 are identified and included in the information set forth in this Compliance Review Form.

Signature	7/12/13 Date

Mr. James A. Keeler

Name (Print or Type)

General Manager, PES Refinery

Title

Division	Source	Permit #	Issue Date	Expiration Date
Philadelphia Refinery	210 Temporary Cooling Tower	13039	5/1/2013	3/31/2014
Philadelphia Refinery	433 Flare Tip Replacement	13074	3/18/2013	3/18/2014
Philadelphia Refinery	14- unit Train Crude Unloading	13020	4/8/2013	4/8/2014
Philadelphia Refinery	2013 Tanks Degassing Permit	13009	2/6/2013	12/31/2013
Philadelphia Refinery	General Plan Approval - Tank PB 843	13001	01/22/13	07/23/14
Philadelphia Refinery	Existing air compressor and pumps (4)	12000	10/12/2012	10/12/2013
Philadelphia Refinery	Existing air compressor and pumps (4)	12001	10/12/2012	10/12/2013
Philadelphia Refinery	Existing air compressor and pumps (4)	12002	10/12/2012	10/12/2013
Philadelphia Refinery	Existing air compressor and pumps (4)	12003	10/12/2012	10/12/2013
Philadelphia Refinery	No. 4 Separator during P401B repair	12198	10/12/2012	10/12/2013
Philadelphia Refinery	WWTP Air compressors during blower repairs	12186	10/12/2012	10/12/2013
Philadelphia Refinery	WWTP Air compressors during blower repairs	12187	10/12/2012	10/12/2013
Philadelphia Refinery	WWTP Air compressors during blower repairs	12188	10/12/2012	10/12/2013
Philadelphia Refinery	WWTP Air compressors during blower repairs	12189	10/12/2012	10/12/2013
Philadelphia Refinery	12 diesel permits from Consent Order	11362-11374	9/14/2012	9/14/2013
Philadelphia Refinery	2 Diesel Powered RICE flood control pumps - Owned	12098	8/6/2012	8/6/2013
Philadelphia Refinery	2 Diesel Powered RICE flood control pumps - Owned	12099	8/6/2012	8/6/2013
Philadelphia Refinery	1232 Incorporating NOx and SO2 limits	11353	7/30/2012	1/28/2014
Philadelphia Refinery	#2 Separator Pump Repair	12148	7/9/2012	7/9/2013
Philadelphia Refinery	433 Temporary rental HF Mitigation Water Pump (Diesel RICE)	12152	7/9/2012	7/9/2013
Philadelphia Refinery	GP 682 Temp Diesel Pump	12140	6/18/2012	6/18/2013
Philadelphia Refinery	Temp Backup Bluebird Compressor	12133	6/13/2012	6/13/2013
Philadelphia Refinery	3 Sep Remediation System	12127	6/12/2012	6/12/2013
Philadelphia Refinery	4 Temp Compressors GP WWTP	12008 - 12011	6/1/2012	6/1/2013
Philadelphia Refinery	Temporary Bluebird Compressors	12128 & 12129	6/1/2012	6/2/2013
Philadelphia Refinery	PB Degreasers	12070 & 12071	5/21/2012	5/21/2013
Philadelphia Refinery	Fire and HF Mitigation RICE	11246-11352	2/23/2012	2/23/2013
Philadelphia Refinery	24P1 Diesel RICE Fire Pump	11329	2/23/2012	2/23/2013
Philadelphia Refinery	Pollock St Remediation	12013	2/21/2012	2/21/2013
Philadelphia Refinery	Penrose Remediation	11277	2/6/2012	2/6/2013
Philadelphia Refinery	Cleaver-Brooks Warehouse Boiler	11276	2/6/2012	2/5/2013
Philadelphia Refinery	2012 Tanks Degassing	11415	1/27/2012	12/31/2012
Philadelphia Refinery	Boilers/Flares/Heaters NSPS per CD	11079	9/23/2011	3/23/2013
Philadelphia Refinery	2011 Annual TO Tanks, amended	11026	9/12/2011	12/31/2012
Philadelphia Refinery	Tks 34/1205/24 Degassing	11166	7/13/2011	12/31/2011
Philadelphia Refinery	New No. 4 Fire Pump	11101	6/24/2011	6/23/2012
Philadelphia Refinery	2011 Annual TO Tanks	11026	2/4/2011	12/31/2011
Philadelphia Refinery	GP 1101 Reactivation Plan	11001	1/25/2011	7/25/2012
Philadelphia Refinery	No. 3 Boiler House, Shutdown #38 boiler	8080	11/2/2010	5/2/2012
Philadelphia Refinery	210 Unit H-201 CD NOx Permit	10180	9/9/2010	8/3/2012
Philadelphia Refinery	137 Oil/Water Separator Carbon	10186	8/6/2010	8/6/2011
Philadelphia Refinery	Tank 1051 EFR Odor Control	10185	8/6/2010	8/6/2011
Philadelphia Refinery	1232 Flare vents to RFG	10121	5/19/2010	5/19/2011
Philadelphia Refinery	1214 Tk (Bz) Seal Change to Dbl Wiper	10116	4/21/2010	10/21/2011
Philadelphia Refinery	Ther Ox for All Degassed Tks in 2010	10046	3/5/2010	12/31/2010
Philadelphia Refinery	Unit 1332 H-400/401 to SCR for CD Nox Control	9040	2/1/2010	8/2/2011
Philadelphia Refinery	Ther. Ox for PB 162 & 204	10001	1/8/2010	1/8/2011
Philadelphia Refinery	Unit 433 Flare Tip & Pilot Gas	9190	12/15/2009	12/15/2010
Philadelphia Refinery	Unit 433 Alt. Disposition to Unit 137 Desalter	9116	6/5/2009	6/5/2010
Philadelphia Refinery	Temp Ther Ox at PB-33,37,38,39	9050	4/17/2009	4/17/2010
Philadelphia Refinery	TO for PB-33/37/38/39	9050	4/14/2009	4/14/2010
Philadelphia Refinery	Unit 137 Foul Gases Re-route	9022	3/3/2009	12/31/2010
Philadelphia Refinery	Unit 865 Improvements	8255	2/23/2009	8/23/2010
Philadelphia Refinery	Install Pollution Controls at #3 Boilerhouse	8080	9/9/2008	3/9/2010
Philadelphia Refinery	Instal pumps and corrosion probes at 210	8153	7/24/2008	6/27/2009
Philadelphia Refinery	TempTher Ox at PB-34	8180	7/1/2008	7/1/2009
Philadelphia Refinery	Operate a thermal Oxidizer	8096	5/14/2008	5/14/2009
Philadelphia Refinery	Install an LCO heat exchanger at 868	8048	2/27/2008	3/27/2009
Philadelphia Refinery	Reactivate PB 843 Tank	8044	2/21/2008	8/21/2009
Philadelphia Refinery	Instal UNLB at 137 F-3	7163	2/5/2008	8/5/2009
Philadelphia Refinery	Reactivate 859 Unit	6144	1/29/2008	1/29/2010
Philadelphia Refinery	Upgrade PB 128 Tank	7214	12/12/2007	6/12/2008
Philadelphia Refinery	Upgrade single mechanical pump seals	7121	11/11/2007	12/11/2008
Philadelphia Refinery	Upgrade single mechanical pump seals	7210	11/11/2007	12/11/2008
Philadelphia Refinery	Upgrade single mechanical pump seals	7213	11/11/2007	12/11/2008
Philadelphia Refinery	Upgrade single mechanical pump seals	7210	11/11/2007	12/11/2008
Philadelphia Refinery	Operate a thermal Oxidizer	7179	10/10/2007	10/10/2008

Attachment

Division	Source	Permit #	Issue Date	Expiration Date
Philadelphia Refinery	Temporary Thermal Oxidizer	7135	8/28/2007	8/16/2008
Philadelphia Refinery	883 Tank General Permit	7105	6/29/2007	12/29/2008
Philadelphia Refinery	231 Jumpover to 250 Tank	7026	6/13/2007	12/13/2008
Philadelphia Refinery	26th Street Bioremediation Unit Amended Permit	6710	4/30/2007	10/30/2008
Philadelphia Refinery	137 ESDV's	7077	4/24/2007	4/23/2008
Philadelphia Refinery	433 Alkylation Expansion	6050	12/4/2006	6/4/2008
Philadelphia Refinery	1733 Arsine Treater	6142	11/29/2006	11/29/2007
Philadelphia Refinery	Permit Upgrade Part 61 BWON Carbon Canister Control Systems	06111-06116	9/7/2006	9/7/2007
Philadelphia Refinery	Permit Upgrade Part 61 BWON Carbon Canister Control Systems	06111-06116	9/7/2006	9/7/2007
Philadelphia Refinery	869 Condensate Cooler (Cooling tower)	6078	6/28/2006	6/28/2007
Philadelphia Refinery	Burner Replacement 231 B101	6069	6/13/2006	6/13/2007
Philadelphia Refinery	Permit (137 Crude Unit): Installation of HE E-21D and Replacement of E-38	6066	5/23/2006	5/23/2007
Philadelphia Refinery	866 Cat Feed Hydrotreater Modification	5219	3/7/2006	9/7/2007
Philadelphia Refinery	1232 FCCU Expansion Permit	4322	2/28/2006	5/31/2008
Philadelphia Refinery	1232 Cooling Tower Rebuild & 1232 Temporary Cooling Tower Operation	06009, 06012	2/13/2006	2/13/2007
Philadelphia Refinery	1231 & 1232 Flare Tip Maintenance Permit	05199, 05200	11/18/2005	11/17/2006
Philadelphia Refinery	1332 CRUH-2 Hydrobon Heater replacement	5124	10/4/2005	4/4/2007
Philadelphia Refinery	Replacement of 867 SRU DEA and SWS Flare tips	05122, 05123	9/6/2005	9/6/2006
Philadelphia Refinery	865 Ultra Low Sulfur Diesel Permit	4237	8/12/2005	2/12/2007
Philadelphia Refinery	North Flare Tip replacement	4209	9/27/2004	9/27/2005
Philadelphia Refinery	CCR Emergency Generator	4208	8/13/2004	8/13/2005
Philadelphia Refinery	869 Restart Plan Approval	3163	2/4/2004	8/5/2005
Philadelphia Refinery	433 SHU Plan Approval	3124	1/14/2004	7/14/2005
Philadelphia Refinery	870 Plan Approval	2184	12/29/2003	6/29/2005
Philadelphia Refinery	Installation permit; 49 MMBTU/hr gas fired heater (868 8H-101)	3039	7/29/2003	7/29/2004
Philadelphia Refinery	Tank 826	2120	7/2/2002	1/2/2007
Philadelphia Refinery	Plan Approval: FCCU 868 upgrades, including 210 H-201 LNB	184	3/22/2002	9/22/2003
Philadelphia Refinery	Title V	V95-038	1/17/2002	2/15/2007
Schuylkill River Tank Farm	Butane Unloading	12270	3/5/2013	3/5/2014
Schuylkill River Tank Farm	SR-5 Oil Water Separator Sludge Cleaning	12212	10/12/2012	10/12/2013
Schuylkill River Tank Farm	SR-5 Oil Water Separator Sludge Cleaning	12213	10/12/2012	10/12/2013
Schuylkill River Tank Farm	SRTF Flare Temporary Diesel Air Compressor (RICE)	12131	6/1/2012	6/1/2013
Schuylkill River Tank Farm	SRTF Flare Temporary Diesel Air Compressor (RICE)	12132	6/1/2012	6/1/2013
Schuylkill River Tank Farm	Title V	V05-011	2/24/2012	2/23/2017
Schuylkill River Tank Farm	SR90 Degassing	11231	9/20/2011	12/31/2011
Schuylkill River Tank Farm	SR-59 Seal Change	10290	12/6/2010	6/6/2012
Schuylkill River Tank Farm	TO for SR-20 & GP 1218	9181	9/9/2009	9/18/2010
Schuylkill River Tank Farm	TO for SR-7	9127	4/10/2009	3/10/2010
Schuylkill River Tank Farm	Tem Ther Ox at SR-6,7,8	9048	3/31/2009	3/31/2010
Schuylkill River Tank Farm	Tem Ther Ox at SR-35,36	9043	3/23/2009	3/23/2010
Schuylkill River Tank Farm	Upgrade SR-41	8154	7/21/2008	7/21/2009
Schuylkill River Tank Farm	Upgrade SR-41	8155	7/21/2008	7/21/2009
Schuylkill River Tank Farm	Operate a thermal Oxidizer	8152	7/1/2008	7/1/2009
Schuylkill River Tank Farm	Upgrade SR-62	8097	5/16/2008	11/16/2009
Schuylkill River Tank Farm	Upgrade SR-7	8068	4/2/2008	10/2/2009

Attachment D
Emissions Calculations

PES Refinery
Heater Firing Rate Increase Plan Approval
PSD/NSR Analysis

Heater Firing Rate Increase Plan Approval Emissions

Source	Pollutant (TPY)									
	NO_x	SO_2	CO	VOC	PM	$PM_{10}/PM_{2.5}$	H_2SO_4	Lead	HAP	CO_2e
Target Heater Emissions	53.8	2.5	78.5	5.1	7.1	7.1	0	4.7E-04	0	112,420
Ancillary Upstream/Downstream Units	4.2	1.3	18.9	11.7	0.03	0.03	0	0	0	4,312
Ancillary Upstream/Downstream Unmodified Heaters/Boiler	82.1	3.2	94.2	6.3	6.1	6.1	0	6.1E-04	0	138,640
Total Plan Approval Emissions	**140.1**	**7.1**	**191.6**	**23.2**	**13.2**	**13.2**	**0.0**	**1.1E-03**	**0.0**	**255,372**

Step 1. PSD Emissions Analysis

Emissions	Pollutant (TPY)							
	NO_2	SO_2	CO	PM	PM_{10}	H_2SO_4	Lead	CO_2e
Heater Firing Rate Increase Plan Approval	140.1	7.1	191.6	13.2	13.2	0.0	1.1E-03	255,372
PSD Significant Level	40	40	100	25	15	7	0.6	75,000
PSD Triggered (Before Netting Analysis)	**Yes**	**No**	**Yes**	**No**	**No**	**No**	**No**	**Yes**

Step 2. PSD Netting Analysis

Emissions	NO_2 Emissions (TPY)	CO Emissions (TPY)	CO_2e Emissions (TPY)
Heater Firing Rate Increase Plan Approval	140.1	191.6	255,372
Contemporaneous Increases/Decreases	-320.7	-17.5	-310,956
Total	**-180.7**	**174.1**	**-55,583**
PSD Significance Level	40	100	75,000
PSD Review Required	**No**	**Yes**	**No**

NA-NSR Ozone Netting Analysis

Plan Approval	5-year NO_x (TPY)	5-year VOC (TPY)
Heater Firing Rate Increase Plan Approval	140.1	23.2
Contemporaneous Increases	10.7	2.8
Net Emissions Increase	**150.7**	**26.0**
Internal Offsets required (1.3:1 Ratio)	195.9	33.8
Netting Credits Applied	-195.9	-33.8
Net Emissions (After Offsetting, if applicable)	**0.0**	**0.0**
NA-NSR Significance Level	**25**	**25**
NA-NSR Review Required	**No**	**No**

NA-NSR Ozone Netting Analysis

Plan Approval	10-year NO_x (TPY)	10-year VOC (TPY)
Heater Firing Rate Increase Plan Approval	140.1	23.2
Contemporaneous Increases/Decreases	-296.7	-11.4
Net Emissions Increase	**-156.7**	**11.7**
NA-NSR Significance Level	**25**	**25**
NA-NSR Review Required	**No**	**No**

NA-NSR $PM_{2.5}$ Emissions Analysis

Plan Approval	SO_2 (TPY)	NO_x (TPY)	$PM_{2.5}$ (TPY)
Heater Firing Rate Increase Plan Approval	7.1	140.1	13.2
NA-NSR Significance Level	**40**	**40**	**10**
NA-NSR Triggered (Before Netting Analysis)	**No**	**Yes**	**Yes**

NA-NSR $PM_{2.5}$ Netting Analysis

Plan Approval	NO_x (TPY)	$PM_{2.5}$ (TPY)
Heater Firing Rate Increase Plan Approval	140.1	13.2
Contemporaneous Increases/Decreases	-320.7	-22.3
Net Emissions Increase	**-180.7**	**-9.0**
NA-NSR Significance Level	**40**	**10**
NA-NSR Review Required	**No**	**No**

PES Refinery
Heater Firing Rate Increase Plan Approval
Summary of Contemporaneous Period Emissions

Facility	Permit No.	Activity	Effective Date of Change	NA-NSR Net Emission Change, Ton/Yr				
				VOC	NO_x	$PM_{2.5}$	$PM_{2.5}/NO_x$	$PM_{2.5}/SO_2$
Point Breeze	02184	Tier II Gasoline	12/29/2003	0.00	0.00	0.00	0.00	68.59
Point Breeze	02184	Htr. 13H1 Fuel Switch Under Tier II	12/29/2003	0.00	0.00	0.00	0.00	-29.70
Marcus Hook	Delaware permit	Sulfur Recovery Unit (done in Delaware)	3/26/2003	0.40	0.00	0.56	0.00	0.00
Point Breeze	03124	433 Alkylation Reappl.	1/4/2004	0.00	0.00	0.00	0.00	0.00
Point Breeze	03163	869 Alky. Reactivation	2/5/2004	0.00	0.00	0.00	0.00	0.40
Marcus Hook	Pa23-0001 U & W	LSG Revised took out Hydrogen plant etc	2/24/2004	6.40	23.00	6.20	23.00	29.77
Point Breeze	04208	Emergency Generator	8/13/2004	0.00	0.00	0.00	0.00	0.07
Gir. Pt./Pt. Br.	04237	865 ULSD	8/12/2005	0.00	0.00	0.00	0.00	7.36
Gir. Pt./Pt. Br.	04322	1232 Flue Gas Treating & Expansion	2/28/2006	0.00	0.00	1.23	0.00	12.55
Marcus Hook	De minimis	Alky cooling project- chill the feed with rental	3/3/2006	0.07	0.99	0.16	0.99	0.13
Point Breeze	05219	866 Unit Modification for ULSD mode	3/7/2006	0.00	0.00	0.00	0.00	1.07
Girard Point	06050	433 HFAU Process Improvement Project	12/4/2006	0.00	0.00	1.88	0.00	36.35
Girard Point	07026	231 Imported Jet Project	6/13/2007	0.00	0.00	0.51	0.00	2.51
Gir. Pt./Pt. Br.	06144	859 ULSD Project	1/29/2008	0.00	0.00	7.50	0.00	23.49
Girard Point	08080	No. 3 Boiler House NO_x Reduction	9/9/2008	12.52	0.00	ND*	0.00	0.00
Girard Point	RFD	Unit 433 KOH Treater Lines	10/23/2008	0.01	0.19	0.01	0.19	0.05
Point Breeze	RFD	Unit 866 Stripper Valve	12/22/2008	0.30	0.06	0.00	0.06	0.04
Point Breeze	08255	Unit 865 Improvement Project	2/23/2009	0.97	9.42	0.27	9.42	5.94
Girard Point	09022	Unit 137 RFG Changes	3/3/2009	0.02	0.00	0.00	0.00	0.00
Girard Point	09116	Unit 433 ASO to Unit 137 Desalter	6/5/2009	0.02	0.00	0.00	0.00	0.00
Marcus Hook	Pa23-0001AA	12 - 3 New Cooling Tower	10/28/2009	0.00	0.00	-0.40	0.00	0.00
Girard Point	09040	Unit 1332 Heater SEP	2/1/2010	0.03	0.87	0.04	0.87	0.23
Point Breeze	non permit letter	Tk 33/35 Jump-over line	11/23/2010	0.03	0.00	0.00	0.00	0.00
Point Breeze	non permit letter	22 Boilerhouse #2/#3	1/19/2010	-0.99	-36.40	-1.41	-36.40	-1.25
Marcus Hook	non permit letter	15-1 CRUDE HTR shutdown	8/16/2012	-5.05	-136.46	-7.02	-136.46	-0.15
Marcus Hook	non permit letter	17-2A H-01, H-02, H-03 HTR shutdown	8/16/2012	-2.72	-57.04	-3.75	-57.04	-0.05
Marcus Hook	non permit letter	17-2A H-04 HTR shutdown	8/16/2012	-0.35	-6.21	-0.50	-6.21	-0.01
Marcus Hook	non permit letter	12-3 CRUDE HTR H-3006 shutdown	8/16/2012	-4.61	-89.48	-6.36	-89.48	-0.13
Marcus Hook	non permit letter	12-3 DESULF HTR	8/16/2012	-0.33	-6.06	-0.48	-6.06	-0.01
Marcus Hook	non permit letter	111 Cooling Towers	8/16/2012	-19.94	0.00	-10.24	0.00	0.00
Gir. Pt./Pt. Br.	RFD	3-Unit Train - Crude Transfer Pipeline	1/18/2013	0.004	0.00	0.00	0.00	0.00
Point Breeze	13001	Tank P-590 (PB 843) Reactivation	1/22/2013	1.24	0.27	0.05	0.27	0.18
Gir. Pt./Pt. Br.	12270	Butane Truck Unloading at SRTF	3/5/2013	0.26	0.09	0.00	0.09	0.00
Gir. Pt./Pt. Br.	13020	14-Unit Train - Crude Transfer Pipeline	4/8/2013	0.25	0.00	0.00	0.00	0.00
5-calendar year increases from 3rd Quarter 2013 (PES/Marcus Hook)				**2.82**	**10.66**	**- - -**	**- - -**	**- - -**
10-year increases/decreases from 3rd Quarter 2013 (PES/Marcus Hook)				**-11.45**	**-296.74**	**- - -**	**- - -**	**- - -**
5-year increases/decreases from 3rd Quarter 2013 (PES/Marcus Hook)				**- - -**	**- - -**	**-22.26**	**-320.73**	**28.32**

Notes:

Plan Approval 04237 triggered NSR for VOC.

Plan Approval 06144 triggered NSR for VOC & NO_x. Plan Approval Application submitted January 29, 2008.

NSR contemporaneous period for VOC and NO_x is 5 calendar years (the year of modification plus back 4 more years).

Under 51 CFR Appendix S, netting analysis for $PM_{2.5}$ only required if project itself leads to a significant increase.

* No. 3 BH $PM_{2.5}$ reduction may be bankable to an ERC after SIP rule change. Will need $PM_{2.5}$ factor from a surrogate unit test to determine the value.

Consent Decree does not allow NO_x reduction within the No. 3 Boiler House Project.

Tank P-590 (PB 843) includes emissions from steam from No. 3 Boiler House that were already permitted in No. 3 Boiler House NO_x Reduction Project in 2008.

PES Refinery
Heater Firing Rate Increase Plan Approval
Summary of Contemporaneous Period Emissions

Facility	Permit No.	Activity	Effective Date of Change	PSD Net Emission Change, Ton/Yr						
				NO_2	SO_2	PM/PM_{10}	CO	H_2SO_4	Lead	CO_2e
Girard Point	08080	No. 3 Boiler House NO_x Reduction[2]	9/9/2008	n/a	n/a	n/a	82.40	n/a		
Girard Point	RFD	Unit 433 KOH Treater Lines	10/23/2008	0.19	0.05	0.01	0.10	n/a		
Point Breeze	RFD	Unit 866 Stripper Valve	12/22/2008	0.06	0.04	0.00	0.04	n/a		
Point Breeze	08255	Unit 865 Improvement Project	2/23/2009	9.42	5.94	0.27	12.01	n/a		
Girard Point	09022	Unit 137 RFG Changes	3/3/2009	0.00	0.00	0.00	0.00	n/a		
Girard Point	09116	Unit 433 ASO to Unit 137 Desalter	6/5/2009	0.00	0.00	0.00	0.00	n/a		
Point Breeze	06144	859 ULSD Project[1]	10/16/2009	note 3	23.49	7.50	87.67	n/a		
Marcus Hook	Pa23-0001AA	12 - 3 New Cooling Tower	10/28/2009	0.00	0.00	-0.40	0.00	0.00		
Girard Point	09040	Unit 1332 Heater SEP	2/1/2010	0.87	0.23	0.04	0.48	2.75		
Marcus Hook	Pa23-0001AD	CO controls for 6 WWTA diesels	5/17/2012	0.00	0.00	0.00	-1.65	0.00	0.00	0.00
Point Breeze	non permit letter	22 Boilerhouse #2/#3	1/19/2010	-36.40	-1.25	-1.41	-0.38	n/a	0.00	-49,788
Marcus Hook	non permit letter	15-1 CRUDE HTR shutdown	8/16/2012	-136.46	-0.15	-7.02	-77.24	n/a	0.00	-111,102
Marcus Hook	non permit letter	17-2A H-01, H-02, H-03 HTR shutdown	8/16/2012	-57.04	-0.05	-3.75	-41.19	n/a	0.00	-44,912
Marcus Hook	non permit letter	17-2A H-04 HTR shutdown	8/16/2012	-6.21	-0.01	-0.50	-5.25	n/a	0.00	-8,250
Marcus Hook	non permit letter	12-3 CRUDE HTR H-3006 shutdown	8/16/2012	-89.48	-0.13	-6.36	-70.37	n/a	0.00	-92,084
Marcus Hook	non permit letter	12-3 DESULF HTR	8/16/2012	-6.06	-0.01	-0.48	-5.09	n/a	0.00	-4,819
Marcus Hook	non permit letter	111 Cooling Towers	8/16/2012	0.00	0.00	-10.24	0.00	n/a	0.00	0.00
Gir. Pt./Pt. Br.	RFD	3-Unit Train - Crude Transfer Pipeline	1/18/2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Point Breeze	13001	Tank P-590 (PB 843) Reactivation[3]	1/22/2013	0.27	0.18	0.05	0.45	0.00	0.00	0.00
Gir. Pt./Pt. Br.	12270	Butane Truck Unloading at SRTF	3/5/2013	0.09	0.00	0.00	0.51	0.00	0.00	0.00
Gir. Pt./Pt. Br.	13020	14-Unit Train - Crude Transfer Pipeline	4/8/2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5-year increases and decreases from 3rd Quarter 2013 (PES/Marcus Hook)				**-320.73**	**28.32**	**-22.26**	**-17.49**	**2.75**	**0.00**	**-310,956**

Notes:

1 The 859 project triggered PSD review for NO_2. Net emission increases for this pollutant were reset with ambient air quality modeling.

Date of startup of Unit 859 following Plan Approval 06144 was October 16, 2009.

Net* = Past five years (date of startup of new project back to date 5 years prior to start of construction, or back to last major PSD permit).

H_2SO_4 is an issue with SCR installation due to small conversion of SO_2 to SO_3 and hydrolization to H_2SO_4.

2 SO_2 and PM reductions per No. 3 BH Consent Decree are not allowable as PSD/NSR credits.

3 Tank P-590 (PB 843) includes emissions from steam from No. 3 Boiler House that were already permitted in No. 3 Boiler House NOx Reduction Project in 2008.

Facility	Permit No.	Source	Effective Date	Creditable Emissions Reductions, Tons						
				VOC	NO_x/NO_2	SO_2	$PM/PM_{10}/PM_{2.5}$	CO	H_2SO_4	CO_2e
Point Breeze	non permit letter	22 Boilerhouse #2/#3	1/19/2010	-0.99	-36.40	-1.25	-1.41	-0.38	n/a	-49,788
Marcus Hook	non permit letter	15-1 CRUDE HTR shutdown	8/16/2012	-5.05	-136.46	-0.15	-7.02	-77.24	n/a	-111,102
Marcus Hook	non permit letter	17-2A H-01, H-02, H-03 HTR shutdown	8/16/2012	-2.72	-57.04	-0.05	-3.75	-41.19	n/a	-44,912
Marcus Hook	non permit letter	17-2A H-04 HTR shutdown	8/16/2012	-0.35	-6.21	-0.01	-0.50	-5.25	n/a	-8,250
Marcus Hook	non permit letter	12-3 CRUDE HTR H-3006 shutdown	8/16/2012	-4.61	-89.48	-0.13	-6.36	-70.37	n/a	-92,084
Marcus Hook	non permit letter	12-3 DESULF HTR	8/16/2012	-0.33	-6.06	-0.01	-0.48	-5.09	n/a	-4,819
Marcus Hook	non permit letter	111 Cooling Towers	8/16/2012	-19.94	0.00	0.00	-10.24	0.00	n/a	0
Total ERCs Generated				-33.97	-331.64	-1.60	-29.74	-199.50	0.00	-310,956
Ozone NA-NSR 5-calendar year review netting credits required				-33.80	-195.95	- - -	- - -	- - -	- - -	- - -
Ozone NA-NSR 10-year review netting credits required				- - -	- - -	- - -	- - -	- - -	- - -	- - -
PM2.5 NA-NSR 5-year review netting credits required				- - -	- - -	- - -	- - -	- - -	- - -	- - -
NSR maximum netting credits needed in the Heater Plan Approval Application				-33.80	-195.95	0.00	0.00	0.00	- - -	0
Total ERCs Remaining after Heater Plan Approval				-0.18	-135.69	-1.60	-29.74	-199.50	0.00	-310,956

PES Refinery
Heater Firing Rate Increase Plan Approval
Emission Estimates for Target Heaters with Proposed Increases in Firing Limits

Source	Emissions	Calculation	PM (TPY)	PM_{10} (TPY)	$PM_{2.5}$ (TPY)	CO (TPY)	VOC (TPY)	NO_x (TPY)	SO_2 (TPY)	Lead (TPY)	CO_2e (TPY)
Unit 231-B101	(A) Baseline Actual Emissions (TPY)	See "Heater Monthly Emissions" tab	1.7	1.7	1.7	18.5	1.2	28.1	0.3	1.1E-04	26,515
	(B) Projected Actual Emissions (TPY)	See "Unit 231 B101 - Proj. Actual" tab	3.1	3.1	3.1	34.4	2.3	12.8	0.8	2.0E-04	49,253
	(C) Baseline Increases (TPY)	(C) = (B) - (A)	1.4	1.4	1.4	15.9	1.0	-15.3	0.4	9.5E-05	22,738
	(D) Capable Emissions (TPY)	See "Unit 231 B101 - Capable" tab	1.5	1.5	1.5	16.8	1.1	-	0.4	1.0E-04	24,046
	(E) Capable Increases from Baseline (TPY)	(E) = (D) - (A)	-0.2	-0.2	-0.2	-1.7	-0.1	-	0.0	-1.0E-05	-2,469
	(F) Plan Approval Emissions Increase (TPY)	**(F) = (C) - (E)**	**1.4**	**1.4**	**1.4**	**15.88**	**1.0**	**0.0**	**0.4**	**9.5E-05**	**22,738**
Unit 865-11H1	(A) Baseline Actual Emissions (TPY)	See "Heater Monthly Emissions" tab	1.7	1.7	1.7	18.9	1.2	26.2	0.4	1.1E-04	27,003
	(B) Projected Actual Emissions (TPY)	See "Unit 865 11H1 - Proj. Actual" tab	2.6	2.6	2.6	28.5	1.9	10.5	0.7	1.7E-04	40,777
	(C) Baseline Increases (TPY)	(C) = (B) - (A)	0.9	0.9	0.9	9.6	0.6	-15.7	0.2	5.7E-05	13,774
	(D) Capable Emissions (TPY)	See "Unit 865 11H1 - Capable" tab	1.9	1.9	1.9	20.8	1.4	-	0.5	1.2E-04	29,799
	(E) Capable Increases from Baseline (TPY)	(E) = (D) - (A)	0.2	0.2	0.2	2.0	0.1	-	0.1	1.2E-05	2,796
	(F) Plan Approval Emissions Increase (TPY)	**(F) = (C) - (E)**	**0.7**	**0.7**	**0.7**	**7.67**	**0.5**	**0.0**	**0.2**	**4.6E-05**	**10,978**
Unit 865-11H2	(A) Baseline Actual Emissions (TPY)	See "Heater Monthly Emissions" tab	1.3	1.3	1.3	14.1	0.9	19.5	0.3	8.4E-05	20,131
	(B) Projected Actual Emissions (TPY)	See "Unit 865 11H2 - Proj. Actual"	1.8	1.8	1.8	20.4	1.3	28.3	0.5	1.2E-04	29,168
	(C) Baseline Increases (TPY)	(C) = (B) - (A)	0.6	0.6	0.6	6.3	0.4	8.7	0.2	3.8E-05	9,038
	(D) Capable Emissions (TPY)	See "Unit 865 11H2 - Capable" tab	1.2	1.2	1.2	13.1	0.9	18.1	0.3	7.8E-05	18,698
	(E) Capable Increases from Baseline (TPY)	(E) = (D) - (A)	-0.1	-0.1	-0.1	-1.0	-0.1	-1.4	0.0	-6.0E-06	-1,432
	(F) Plan Approval Emissions Increase (TPY)	**(F) = (C) - (E)**	**0.6**	**0.6**	**0.6**	**6.31**	**0.4**	**8.7**	**0.2**	**3.8E-05**	**9,038**
Unit 210-H101	(A) Baseline Actual Emissions (TPY)	See "Heater Monthly Emissions" tab	5.2	5.2	5.2	56.9	3.7	62.1	2.0	3.4E-04	81,546
	(B) Projected Actual Emissions (TPY)	See "Unit 210 H101 - Proj. Actual"	6.1	6.1	6.1	66.9	4.4	73.1	2.7	4.0E-04	95,847
	(C) Baseline Increases (TPY)	(C) = (B) - (A)	0.9	0.9	0.9	10.0	0.7	11.0	0.7	5.9E-05	14,301
	(D) Capable Emissions (TPY)	See "Unit 210 H101 - Capable" tab	4.9	4.9	4.9	53.7	3.5	58.7	2.2	3.2E-04	76,940
	(E) Capable Increases from Baseline (TPY)	(E) = (D) - (A)	-0.3	-0.3	-0.3	-3.2	-0.2	-3.4	0.1	-1.9E-05	-4,606
	(F) Plan Approval Emissions Increase (TPY)	**(F) = (C) - (E)**	**0.9**	**0.9**	**0.9**	**9.99**	**0.7**	**11.0**	**0.5**	**5.9E-05**	**14,301**
Unit 210-H201	(A) Baseline Actual Emissions (TPY)	See "Heater Monthly Emissions" tab	5.9	5.9	5.9	65.1	4.3	20.1	2.1	3.9E-04	93,174
	(B) Projected Actual Emissions (TPY)	See "Unit 210 H201 - Proj. Actual" tab	8.0	8.0	8.0	88.5	5.8	32.6	3.2	5.3E-04	126,707
	(C) Baseline Increases (TPY)	(C) = (B) - (A)	2.1	2.1	2.1	23.4	1.5	12.5	1.1	1.4E-04	33,532
	(D) Capable Emissions (TPY)	See "Unit 210 H201 - Capable" tab	5.9	5.9	5.9	65.2	4.3	16.9	2.3	3.9E-04	93,422
	(E) Capable Increases from Baseline (TPY)	(E) = (D) - (A)	0.0	0.0	0.0	0.2	0.0	-3.1	0.2	1.0E-06	248
	(F) Plan Approval Emissions Increase (TPY)	**(F) = (C) - (E)**	**2.1**	**2.1**	**2.1**	**23.24**	**1.5**	**12.5**	**0.8**	**1.4E-04**	**33,284**
Unit 866-12H1	(A) Baseline Actual Emissions (TPY)	See "Heater Monthly Emissions" tab	0.6	0.6	0.6	6.6	0.4	9.1	0.2	3.9E-05	9,446
	(B) Projected Actual Emissions (TPY)	See "Unit 866 12H1 - Proj. Actual" tab	1.7	1.7	1.7	18.6	1.2	25.8	0.5	1.1E-04	26,601
	(C) Baseline Increases (TPY)	(C) = (B) - (A)	1.1	1.1	1.1	12.0	0.8	16.6	0.3	7.1E-05	17,156
	(D) Capable Emissions (TPY)	See "Unit 866 12H1 - Capable" tab	0.5	0.5	0.5	5.8	0.4	8.1	0.2	3.5E-05	8,367
	(E) Capable Increases from Baseline (TPY)	(E) = (D) - (A)	-0.1	-0.1	-0.1	-0.8	0.0	-1.0	0.0	-4.5E-06	-1,078
	(F) Plan Approval Emissions Increase (TPY)	**(F) = (C) - (E)**	**1.1**	**1.1**	**1.1**	**11.98**	**0.8**	**16.6**	**0.3**	**7.1E-05**	**17,156**
Unit 868-8H101	(A) Baseline Actual Emissions (TPY)	See "Heater Monthly Emissions" tab	1.2	1.2	1.2	13.2	0.9	19.0	0.4	7.8E-05	18,877
	(B) Projected Actual Emissions (TPY)	See "Unit 868 8H101 - Proj. Actual" tab	1.7	1.7	1.7	18.9	1.2	27.1	0.6	1.1E-04	27,054
	(C) Baseline Increases (TPY)	(C) = (B) - (A)	0.5	0.5	0.5	5.7	0.4	8.1	0.2	3.4E-05	8,177
	(D) Capable Emissions (TPY)	See "Unit 868 8H101 - Capable" tab	1.4	1.4	1.4	15.5	1.0	22.2	0.5	9.2E-05	22,130
	(E) Capable Increases from Baseline (TPY)	(E) = (D) - (A)	0.2	0.2	0.2	2.3	0.1	3.2	0.1	1.4E-05	3,253
	(F) Plan Approval Emissions Increase (TPY)	**(F) = (C) - (E)**	**0.3**	**0.3**	**0.3**	**3.44**	**0.2**	**4.9**	**0.1**	**2.0E-05**	**4,924**
Total	(A) Baseline Actual Emissions (TPY)	Sum of all (A) rows above	17.5	17.5	17.5	193.2	12.7	184.1	5.8	1.2E-03	276,692
	(B) Projected Actual Emissions (TPY)	Sum of all (B) rows above	25.0	25.0	25.0	276.1	18.1	210.2	9.0	1.6E-03	395,408
	(C) Baseline Increases (TPY)	Sum of all (C) rows above	7.5	7.5	7.5	82.9	5.4	26.0	3.1	4.9E-04	118,716
	(D) Capable Emissions (TPY)	Sum of all (D) rows above	17.3	17.3	17.3	190.9	12.5	124.0	6.4	1.1E-03	273,402
	(E) Capable Increases from Baseline (TPY)	Sum of all (E) rows above	-0.2	-0.2	-0.2	-2.3	-0.2	-60.1	0.5	-1.4E-05	-3,289
	Plan Approval Emissions Increase (TPY)	Sum of all (F) rows above	**7.1**	**7.1**	**7.1**	**78.5**	**5.1**	**53.8**	**2.5**	**4.7E-04**	**112,420**

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 2310-B101 Heater Projected Actual Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 231-B101 Heater Current Firing Rate Limit	=	91.00	MMBtu/hr	
[B]	Unit 231-B101 Heater Future Annual Average Firing Rate	=	97.75	MMBtu/hr	
[C]	Unit 231-B101 Heater Future Hourly Maximum Firing Rate	=	104.50	MMBtu/hr	
[D]	Projected Maximum Annual Firing Rate	=	856,000	MMBtu/yr	= [B] * 8760 (Rounded to nearest thousand MMBtu)
[E]	Higher heating value of fuel gas	=	1,045.2	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0019	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.030	lb/MMBtu	Design rate for new ULNBs
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 Projected Actual Emissions	=	0.8	tpy	= [D] * [F] / 2000
[N]	NO_x Projected Actual Emissions	=	12.8	tpy	= [D] * [G] / 2000
[O]	PM Projected Actual Emissions	=	3.1	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} Projected Actual Emissions	=	3.1	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ Projected Actual Emissions	=	3.1	tpy	= [D] * [J] / [E] / 2000
[R]	CO Projected Actual Emissions	=	34.4	tpy	= [D] * [K] / [E] / 2000
[S]	VOC Projected Actual Emissions	=	2.3	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.15	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	49,253	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead Projected Actual Emissions	=	2.0E-04	tpy	= [D] * [AD] / [E] / 2000
[AF]	SO_2 maximum hourly	=	0.2	lb/hr	= [C] * [F]
[AG]	NO_x maximum hourly	=	3.1	lb/hr	= [C] * [G]
[AH]	PM maximum hourly	=	0.8	lb/hr	= [C] * [H] / [E]
[AI]	PM_{10} maximum hourly	=	0.8	lb/hr	= [C] * [I] / [E]
[AJ]	$PM_{2.5}$ maximum hourly	=	0.8	lb/hr	= [C] * [J] / [E]
[AK]	CO maximum hourly	=	8.4	lb/hr	= [C] * [K] / [E]
[AL]	VOC maximum hourly	=	0.5	lb/hr	= [C] * [L] / [E]
[AM]	Lead maximum hourly	=	5.0E-05	lb/hr	= [C] * [AD] / [E]

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 231-B101 Heater Capable of Accommodating Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 231-B101 Heater Current Firing Rate Limit	=	91.00	MMBtu/hr	
[B]	Unit 231-B101 Heater Maximum Monthly Firing Rate	=	34,825	MMBtu/month	24 month period
[C]	Unit 231-B101 Heater Maximum Monthly Firing Rate	=	48.37	MMBtu/hr	24 month period
[D]	Annual Firing Rate Projected from Maximum Monthly Rate	=	417,902	MMBtu/yr	= [B] * 12
[E]	Higher heating value of fuel gas	=	1,045.2	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0019	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.122	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 PTE	=	0.4	tpy	= [D] * [F] / 2000
[N]	NO_x PTE	=	25.5	tpy	= [D] * [G] / 2000
[O]	PM PTE	=	1.5	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} PTE	=	1.5	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ PTE	=	1.5	tpy	= [D] * [J] / [E] / 2000
[R]	CO PTE	=	16.8	tpy	= [D] * [K] / [E] / 2000
[S]	VOC PTE	=	1.1	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.15	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	24,046	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead PTE	=	1.0E-04	tpy	= [D] * [AD] / [E] / 2000

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 865-11H1 Heater Projected Actual Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 865-11H1 Heater Current Firing Rate Limit	=	72.20	MMBtu/hr	
[B]	Unit 865-11H1 Heater Future Annual Average Firing Rate	=	79.75	MMBtu/hr	
[C]	Unit 865-11H1 Heater Future Hourly Maximum Firing Rate	=	87.30	MMBtu/hr	
[D]	Projected Maximum Annual Firing Rate	=	699,000	MMBtu/yr	= [B] * 8760 (Rounded to nearest thousand MMBtu)
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0019	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.030	lb/MMBtu	Design rate for new ULNBs
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 Projected Actual Emissions	=	0.7	tpy	= [D] * [F] / 2000
[N]	NO_x Projected Actual Emissions	=	10.5	tpy	= [D] * [G] / 2000
[O]	PM Projected Actual Emissions	=	2.6	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} Projected Actual Emissions	=	2.6	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ Projected Actual Emissions	=	2.6	tpy	= [D] * [J] / [E] / 2000
[R]	CO Projected Actual Emissions	=	28.5	tpy	= [D] * [K] / [E] / 2000
[S]	VOC Projected Actual Emissions	=	1.9	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	40,777	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead Projected Actual Emissions	=	1.7E-04	tpy	= [D] * [AD] / [E] / 2000
[AF]	SO_2 maximum hourly	=	0.2	lb/hr	= [C] * [F]
[AG]	NO_x maximum hourly	=	2.6	lb/hr	= [C] * [G]
[AH]	PM maximum hourly	=	0.6	lb/hr	= [C] * [H] / [E]
[AI]	PM_{10} maximum hourly	=	0.6	lb/hr	= [C] * [I] / [E]
[AJ]	$PM_{2.5}$ maximum hourly	=	0.6	lb/hr	= [C] * [J] / [E]
[AK]	CO maximum hourly	=	7.1	lb/hr	= [C] * [K] / [E]
[AL]	VOC maximum hourly	=	0.5	lb/hr	= [C] * [L] / [E]
[AM]	Lead maximum hourly	=	4.2E-05	lb/hr	= [C] * [AD] / [E]

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 865-11H1 Heater Capable of Accommodating Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 865-11H1 Heater Current Firing Rate Limit	=	72.20	MMBtu/hr	
[B]	Unit 865-11H1 Heater Maximum Monthly Firing Rate	=	42,568	MMBtu/month	24 month period
[C]	Unit 865-11H1 Heater Maximum Monthly Firing Rate	=	59.12	MMBtu/hr	24 month period
[D]	Annual Firing Rate Projected from Maximum Monthly Rate	=	510,810	MMBtu/yr	= [B] * 12
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0019	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.113	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 PTE	=	0.5	tpy	= [D] * [F] / 2000
[N]	NO_x PTE	=	28.9	tpy	= [D] * [G] / 2000
[O]	PM PTE	=	1.9	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} PTE	=	1.9	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ PTE	=	1.9	tpy	= [D] * [J] / [E] / 2000
[R]	CO PTE	=	20.8	tpy	= [D] * [K] / [E] / 2000
[S]	VOC PTE	=	1.4	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	29,799	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead PTE	=	1.2E-04	tpy	= [D] * [AD] / [E] / 2000

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 865-11H2 Heater Projected Actual Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 865-11H2 Heater Current Firing Rate Limit	=	49.90	MMBtu/hr	
[B]	Unit 865-11H2 Heater Future Annual Average Firing Rate	=	57.05	MMBtu/hr	
[C]	Unit 865-11H2 Heater Future Hourly Maximum Firing Rate	=	64.20	MMBtu/hr	
[D]	Projected Maximum Annual Firing Rate	=	500,000	MMBtu/yr	= [B] * 8760 (Rounded to nearest thousand MMBtu)
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0020	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.113	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 Projected Actual Emissions	=	0.5	tpy	= [D] * [F] / 2000
[N]	NO_x Projected Actual Emissions	=	28.3	tpy	= [D] * [G] / 2000
[O]	PM Projected Actual Emissions	=	1.8	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} Projected Actual Emissions	=	1.8	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ Projected Actual Emissions	=	1.8	tpy	= [D] * [J] / [E] / 2000
[R]	CO Projected Actual Emissions	=	20.4	tpy	= [D] * [K] / [E] / 2000
[S]	VOC Projected Actual Emissions	=	1.3	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	29,168	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead Projected Actual Emissions	=	1.2E-04	tpy	= [D] * [AD] / [E] / 2000
[AF]	SO_2 maximum hourly	=	0.1	lb/hr	= [C] * [F]
[AG]	NO_x maximum hourly	=	7.3	lb/hr	= [C] * [G]
[AH]	PM maximum hourly	=	0.5	lb/hr	= [C] * [H] / [E]
[AI]	PM_{10} maximum hourly	=	0.5	lb/hr	= [C] * [I] / [E]
[AJ]	$PM_{2.5}$ maximum hourly	=	0.5	lb/hr	= [C] * [J] / [E]
[AK]	CO maximum hourly	=	5.2	lb/hr	= [C] * [K] / [E]
[AL]	VOC maximum hourly	=	0.3	lb/hr	= [C] * [L] / [E]
[AM]	Lead maximum hourly	=	3.1E-05	lb/hr	= [C] * [AD] / [E]

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 865-11H2 Heater Capable of Accommodating Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 865-11H2 Heater Current Firing Rate Limit	=	49.90	MMBtu/hr	
[B]	Unit 865-11H2 Heater Maximum Monthly Firing Rate	=	26,710	MMBtu/month	24 month period
[C]	Unit 865-11H2 Heater Maximum Monthly Firing Rate	=	37.10	MMBtu/hr	24 month period
[D]	Annual Firing Rate Projected from Maximum Monthly Rate	=	320,524	MMBtu/yr	= [B] * 12
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0020	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.113	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 PTE	=	0.3	tpy	= [D] * [F] / 2000
[N]	NO_x PTE	=	18.1	tpy	= [D] * [G] / 2000
[O]	PM PTE	=	1.2	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} PTE	=	1.2	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ PTE	=	1.2	tpy	= [D] * [J] / [E] / 2000
[R]	CO PTE	=	13.1	tpy	= [D] * [K] / [E] / 2000
[S]	VOC PTE	=	0.9	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	18,698	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead PTE	=	7.8E-05	tpy	= [D] * [AD] / [E] / 2000

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 210-H101 Heater Projected Actual Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 210-H101 Heater Current Firing Rate Limit	=	183.00	MMBtu/hr	
[B]	Unit 210-H101 Heater Future Annual Average Firing Rate	=	187.50	MMBtu/hr	
[C]	Unit 210-H101 Heater Future Hourly Maximum Firing Rate	=	192.00	MMBtu/hr	
[D]	Projected Maximum Annual Firing Rate	=	1,643,000	MMBtu/yr	= [B] * 8760 (Rounded to nearest thousand MMBtu)
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0033	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.089	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 Projected Actual Emissions	=	2.7	tpy	= [D] * [F] / 2000
[N]	NO_x Projected Actual Emissions	=	73.1	tpy	= [D] * [G] / 2000
[O]	PM Projected Actual Emissions	=	6.1	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} Projected Actual Emissions	=	6.1	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ Projected Actual Emissions	=	6.1	tpy	= [D] * [J] / [E] / 2000
[R]	CO Projected Actual Emissions	=	66.9	tpy	= [D] * [K] / [E] / 2000
[S]	VOC Projected Actual Emissions	=	4.4	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	95,847	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead Projected Actual Emissions	=	4.0E-04	tpy	= [D] * [AD] / [E] / 2000
[AF]	SO_2 maximum hourly	=	0.6	lb/hr	= [C] * [F]
[AG]	NO_x maximum hourly	=	17.1	lb/hr	= [C] * [G]
[AH]	PM maximum hourly	=	1.4	lb/hr	= [C] * [H] / [E]
[AI]	PM_{10} maximum hourly	=	1.4	lb/hr	= [C] * [I] / [E]
[AJ]	$PM_{2.5}$ maximum hourly	=	1.4	lb/hr	= [C] * [J] / [E]
[AK]	CO maximum hourly	=	15.6	lb/hr	= [C] * [K] / [E]
[AL]	VOC maximum hourly	=	1.0	lb/hr	= [C] * [L] / [E]
[AM]	Lead maximum hourly	=	9.3E-05	lb/hr	= [C] * [AD] / [E]

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 210-H101 Heater Capable of Accommodating Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 210-H101 Heater Current Firing Rate Limit	=	183.00	MMBtu/hr	
[B]	Unit 210-H101 Heater Maximum Monthly Firing Rate	=	109,908	MMBtu/month	24 month period
[C]	Unit 210-H101 Heater Maximum Monthly Firing Rate	=	152.65	MMBtu/hr	24 month period
[D]	Annual Firing Rate Projected from Maximum Monthly Rate	=	1,318,899	MMBtu/yr	= [B] * 12
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0033	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.089	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 PTE	=	2.2	tpy	= [D] * [F] / 2000
[N]	NO_x PTE	=	58.7	tpy	= [D] * [G] / 2000
[O]	PM PTE	=	4.9	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} PTE	=	4.9	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ PTE	=	4.9	tpy	= [D] * [J] / [E] / 2000
[R]	CO PTE	=	53.7	tpy	= [D] * [K] / [E] / 2000
[S]	VOC PTE	=	3.5	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	76,940	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead PTE	=	3.2E-04	tpy	= [D] * [AD] / [E] / 2000

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 210-H201 Heater Projected Actual Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 210-H201 Heater Current Firing Rate Limit	=	242.00	MMBtu/hr	
[B]	Unit 210-H201 Heater Future Annual Average Firing Rate	=	248.00	MMBtu/hr	
[C]	Unit 210-H201 Heater Future Hourly Maximum Firing Rate	=	254.00	MMBtu/hr	
[D]	Projected Maximum Annual Firing Rate	=	2,172,000	MMBtu/yr	= [B] * 8760 (Rounded to nearest thousand MMBtu)
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0029	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.030	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 Projected Actual Emissions	=	3.2	tpy	= [D] * [F] / 2000
[N]	NO_x Projected Actual Emissions	=	32.6	tpy	= [D] * [G] / 2000
[O]	PM Projected Actual Emissions	=	8.0	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} Projected Actual Emissions	=	8.0	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ Projected Actual Emissions	=	8.0	tpy	= [D] * [J] / [E] / 2000
[R]	CO Projected Actual Emissions	=	88.5	tpy	= [D] * [K] / [E] / 2000
[S]	VOC Projected Actual Emissions	=	5.8	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	126,707	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead Projected Actual Emissions	=	5.3E-04	tpy	= [D] * [AD] / [E] / 2000
[AF]	SO_2 maximum hourly	=	0.7	lb/hr	= [C] * [F]
[AG]	NO_x maximum hourly	=	7.6	lb/hr	= [C] * [G]
[AH]	PM maximum hourly	=	1.9	lb/hr	= [C] * [H] / [E]
[AI]	PM_{10} maximum hourly	=	1.9	lb/hr	= [C] * [I] / [E]
[AJ]	$PM_{2.5}$ maximum hourly	=	1.9	lb/hr	= [C] * [J] / [E]
[AK]	CO maximum hourly	=	20.7	lb/hr	= [C] * [K] / [E]
[AL]	VOC maximum hourly	=	1.4	lb/hr	= [C] * [L] / [E]
[AM]	Lead maximum hourly	=	1.2E-04	lb/hr	= [C] * [AD] / [E]

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 210-H201 Heater Capable of Accommodating Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 210-H201 Heater Current Firing Rate Limit	=	242.00	MMBtu/hr	
[B]	Unit 210-201 Heater Maximum Monthly Firing Rate	=	133,453	MMBtu/month	24 month period
[C]	Unit 210-H201 Heater Maximum Monthly Firing Rate	=	185.35	MMBtu/hr	24 month period
[D]	Annual Firing Rate Projected from Maximum Monthly Rate	=	1,601,440	MMBtu/yr	= [B] * 12
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0029	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.021	lb/MMBtu	Actual NOx emission rate during June 2010
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 PTE	=	2.3	tpy	= [D] * [F] / 2000
[N]	NO_x PTE	=	16.9	tpy	= [D] * [G] / 2000
[O]	PM PTE	=	5.9	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} PTE	=	5.9	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ PTE	=	5.9	tpy	= [D] * [J] / [E] / 2000
[R]	CO PTE	=	65.2	tpy	= [D] * [K] / [E] / 2000
[S]	VOC PTE	=	4.3	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	93,422	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead PTE	=	3.9E-04	tpy	= [D] * [AD] / [E] / 2000

Unit 210-H201 Actual NO_x emission rates			
Month	MMBtu fired	Tons NO_x	lb/MMBtu
1/1/2010	167,474	2.44	0.029
2/1/2010	145,603	1.99	0.027
3/1/2010	148,902	1.78	0.024
4/1/2010	135,703	1.51	0.022
5/1/2010	139,001	1.41	0.020
6/1/2010	133,453	1.41	0.021
7/1/2010	132,743	1.41	0.021
8/1/2010	161,623	1.98	0.024
9/1/2010	141,423	1.72	0.024
10/1/2010	137,769	1.65	0.024
11/1/2010	143,317	1.87	0.026
12/1/2010	133,952	1.57	0.023
1/1/2011	131,607	1.45	0.022
2/1/2011	119,956	1.08	0.018
3/1/2011	116,369	1.39	0.024
4/1/2011	104,737	1.33	0.025
5/1/2011	122,289	1.60	0.026
6/1/2011	115,614	1.52	0.026
7/1/2011	111,253	1.60	0.029
8/1/2011	88,518	1.23	0.028
9/1/2011	122,327	2.28	0.037
10/1/2011	149,238	2.19	0.029
11/1/2011	143,349	1.84	0.026
12/1/2011	152,579	1.90	0.025

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 866-12H1 Heater Projected Actual Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 866-12H1 Heater Current Firing Rate Limit	=	43.00	MMBtu/hr	
[B]	Unit 866-12H1 Heater Future Annual Average Firing Rate	=	52.10	MMBtu/hr	
[C]	Unit 866-12H1 Heater Future Hourly Maximum Firing Rate	=	61.20	MMBtu/hr	
[D]	Projected Maximum Annual Firing Rate	=	456,000	MMBtu/yr	= [B] * 8760 (Rounded to nearest thousand MMBtu)
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0022	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.113	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 Projected Actual Emissions	=	0.5	tpy	= [D] * [F] / 2000
[N]	NO_x Projected Actual Emissions	=	25.8	tpy	= [D] * [G] / 2000
[O]	PM Projected Actual Emissions	=	1.7	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} Projected Actual Emissions	=	1.7	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ Projected Actual Emissions	=	1.7	tpy	= [D] * [J] / [E] / 2000
[R]	CO Projected Actual Emissions	=	18.6	tpy	= [D] * [K] / [E] / 2000
[S]	VOC Projected Actual Emissions	=	1.2	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	26,601	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead Projected Actual Emissions	=	1.1E-04	tpy	= [D] * [AD] / [E] / 2000
[AF]	SO_2 maximum hourly	=	0.1	lb/hr	= [C] * [F]
[AG]	NO_x maximum hourly	=	6.9	lb/hr	= [C] * [G]
[AH]	PM maximum hourly	=	0.5	lb/hr	= [C] * [H] / [E]
[AI]	PM_{10} maximum hourly	=	0.5	lb/hr	= [C] * [I] / [E]
[AJ]	$PM_{2.5}$ maximum hourly	=	0.5	lb/hr	= [C] * [J] / [E]
[AK]	CO maximum hourly	=	5.0	lb/hr	= [C] * [K] / [E]
[AL]	VOC maximum hourly	=	0.3	lb/hr	= [C] * [L] / [E]
[AM]	Lead maximum hourly	=	3.0E-05	lb/hr	= [C] * [AD] / [E]

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 866-12H1 Heater Capable of Accommodating Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 866-12H1 Heater Current Firing Rate Limit	=	43.00	MMBtu/hr	
[B]	Unit 866-12H1 Heater Maximum Monthly Firing Rate	=	11,953	MMBtu/month	24 month period
[C]	Unit 866-12H1 Heater Maximum Monthly Firing Rate	=	16.60	MMBtu/hr	24 month period
[D]	Annual Firing Rate Projected from Maximum Monthly Rate	=	143,435	MMBtu/yr	= [B] * 12
[E]	Higher heating value of fuel gas	=	1,030.9	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0022	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.113	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 PTE	=	0.2	tpy	= [D] * [F] / 2000
[N]	NO_x PTE	=	8.1	tpy	= [D] * [G] / 2000
[O]	PM PTE	=	0.5	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} PTE	=	0.5	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ PTE	=	0.5	tpy	= [D] * [J] / [E] / 2000
[R]	CO PTE	=	5.8	tpy	= [D] * [K] / [E] / 2000
[S]	VOC PTE	=	0.4	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	52.87	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	8,367	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead PTE	=	3.5E-05	tpy	= [D] * [AD] / [E] / 2000

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 868-8H101 Heater Projected Actual Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 868- 8H101 Heater Current Firing Rate Limit	=	49.50	MMBtu/hr	
[B]	Unit 868-8H101 Heater Future Annual Average Firing Rate	=	54.75	MMBtu/hr	
[C]	Unit 868-8H101 Heater Future Hourly Maximum Firing Rate	=	60.00	MMBtu/hr	
[D]	Projected Maximum Annual Firing Rate	=	480,000	MMBtu/yr	= [B] * 8760 (Rounded to nearest thousand MMBtu)
[E]	Higher heating value of fuel gas	=	1,067.0	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0026	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.113	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 Projected Actual Emissions	=	0.6	tpy	= [D] * [F] / 2000
[N]	NO_x Projected Actual Emissions	=	27.1	tpy	= [D] * [G] / 2000
[O]	PM Projected Actual Emissions	=	1.7	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} Projected Actual Emissions	=	1.7	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ Projected Actual Emissions	=	1.7	tpy	= [D] * [J] / [E] / 2000
[R]	CO Projected Actual Emissions	=	18.9	tpy	= [D] * [K] / [E] / 2000
[S]	VOC Projected Actual Emissions	=	1.2	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	51.08	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	27,054	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead Projected Actual Emissions	=	1.1E-04	tpy	= [D] * [AD] / [E] / 2000
[AF]	SO_2 maximum hourly	=	0.2	lb/hr	= [C] * [F]
[AG]	NO_x maximum hourly	=	6.8	lb/hr	= [C] * [G]
[AH]	PM maximum hourly	=	0.4	lb/hr	= [C] * [H] / [E]
[AI]	PM_{10} maximum hourly	=	0.4	lb/hr	= [C] * [I] / [E]
[AJ]	$PM_{2.5}$ maximum hourly	=	0.4	lb/hr	= [C] * [J] / [E]
[AK]	CO maximum hourly	=	4.7	lb/hr	= [C] * [K] / [E]
[AL]	VOC maximum hourly	=	0.3	lb/hr	= [C] * [L] / [E]
[AM]	Lead maximum hourly	=	2.8E-05	lb/hr	= [C] * [AD] / [E]

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 868-8H101 Heater Capable of Accommodating Emissions Analysis

ID	Parameter		Value	Units	Source / Basis
[A]	Unit 868-8H101 Heater Current Firing Rate Limit	=	49.50	MMBtu/hr	
[B]	Unit 868-8H101 Heater Maximum Monthly Firing Rate	=	32,720	MMBtu/month	24 month period
[C]	Unit 868-8H101 Heater Maximum Monthly Firing Rate	=	45.44	MMBtu/hr	24 month period
[D]	Annual Firing Rate Projected from Maximum Monthly Rate	=	392,635	MMBtu/yr	= [B] * 12
[E]	Higher heating value of fuel gas	=	1,067.0	Btu/scf	24 month average of HHV of fuel gas
[F]	SO_2 EF	=	0.0026	lb/MMBtu	Based on 2011 SO_2 emissions from Emission Inventory
[G]	NO_x EF	=	0.113	lb/MMBtu	Proposed NO_x RACT Limits
[H]	PM EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[I]	PM_{10} EF	=	7.6	lb/MMscf	AP-42; 7/98; Table 1.4-2
[J]	$PM_{2.5}$ EF	=	7.6	lb/MMscf	Assumed to be the same as PM_{10} emission factor
[K]	CO EF	=	84	lb/MMscf	AP-42; 7/98; Table 1.4-1
[L]	VOC EF	=	5.5	lb/MMscf	AP-42; 7/98; Table 1.4-2
[M]	SO_2 PTE	=	0.5	tpy	= [D] * [F] / 2000
[N]	NO_x PTE	=	22.2	tpy	= [D] * [G] / 2000
[O]	PM PTE	=	1.4	tpy	= [D] * [H] / [E] / 2000
[P]	PM_{10} PTE	=	1.4	tpy	= [D] * [I] / [E] / 2000
[Q]	$PM_{2.5}$ PTE	=	1.4	tpy	= [D] * [J] / [E] / 2000
[R]	CO PTE	=	15.5	tpy	= [D] * [K] / [E] / 2000
[S]	VOC PTE	=	1.0	tpy	= [D] * [L] / [E] / 2000
[T]	CO_2 EF	=	53.02	kg/MMBtu	40 CFR 98 Table C-1
[U]	CH_4 EF	=	0.001	kg/MMBtu	40 CFR 98 Table C-2
[V]	N_2O EF	=	0.0001	kg/MMBtu	40 CFR 98 Table C-2
[W]	Default HHV	=	0.001028	MMBtu/scf	40 CFR 98 Table C-1
[X]	Adjusted CO_2 EF	=	51.08	kg/MMBtu	= [T] * [W] / 1,000,000 * [E]
[Y]	Adjusted CH_4 EF	=	0.001	kg/MMBtu	= [U] * [W] / 1,000,000 * [E]
[Z]	Adjusted N_2O EF	=	0.0001	kg/MMBtu	= [V] * [W] / 1,000,000 * [E]
[AA]	CH_4 Global Warming Potential	=	21		40 CFR 98 Table A-1
[AB]	N_2O Global Warming Potential	=	310		40 CFR 98 Table A-1
[AC]	CO_2e Projected Actual Emissions	=	22,130	tpy CO_2e	= (([D] * [X]) + ([D] * [Y] * [AA]) + ([D] * [Z] * [AB])) / 1,000 * 1.102311311
[AD]	Lead EF	=	0.0005	lb/MMscf	AP-42; 7/98; Table 1.4-2
[AE]	Lead PTE	=	9.2E-05	tpy	= [D] * [AD] / [E] / 2000

PES Refinery
Heater Firing Rate Increase Plan Approval
Target Heater Fired Duties

Month	FIRED DUTY Unit 231-B101	FIRED DUTY Unit 865-11H1	FIRED DUTY Unit 865-11H2	FIRED DUTY Unit 210-H101	FIRED DUTY Unit 210-H201	FIRED DUTY Unit 866-12H1	FIRED DUTY Unit 868-8H101	Total FIRED DUTY
	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU
Jan-10	42,375	47,785	34,153	124,270	167,474	17,754	35,848	469,660
Feb-10	35,110	45,973	31,864	112,764	145,603	18,345	32,741	422,400
Mar-10	46,464	25,650	19,329	114,528	148,902	11,094	31,858	397,826
Apr-10	43,228	42,885	29,961	116,996	135,703	12,919	30,229	411,920
May-10	43,178	47,847	29,954	112,894	139,001	11,979	36,307	421,161
Jun-10	34,825	42,568	26,710	109,908	133,453	11,953	32,720	392,137
Jul-10	34,167	45,644	27,578	113,417	132,743	13,376	23,973	390,897
Aug-10	43,897	43,338	32,173	116,118	161,623	15,245	35,846	448,240
Sep-10	42,980	38,133	29,818	109,541	141,423	13,665	19,965	395,526
Oct-10	37,453	44,274	33,225	119,057	137,769	21,000	26,517	419,296
Nov-10	35,040	39,540	33,058	118,019	143,317	2,011	35,237	406,223
Dec-10	38,046	33,851	32,372	120,112	133,952	10,247	34,539	403,119
Jan-11	45,834	40,264	31,414	117,352	131,607	12,599	35,770	414,840
Feb-11	7,762	35,740	29,138	111,444	119,956	12,047	32,771	348,857
Mar-11	4,080	12,005	9,889	128,112	116,369	15,316	27,437	313,207
Apr-11	28,545	1,545	7,209	122,999	104,737	4,607	22,103	291,745
May-11	47,328	43,406	32,653	116,662	122,289	10,671	25,041	398,051
Jun-11	37,365	38,421	30,314	115,660	115,614	8,960	25,144	371,478
Jul-11	42,374	38,816	29,391	119,003	111,253	11,306	27,107	379,249
Aug-11	42,641	40,901	30,388	123,501	88,518	13,817	30,067	369,833
Sep-11	41,780	39,866	31,807	108,280	122,327	16,926	21,729	382,715
Oct-11	51,500	39,063	32,018	117,347	149,238	16,975	26,829	432,968
Nov-11	47,964	48,434	32,648	117,078	143,349	19,973	12,284	421,730
Dec-11	47,970	51,031	33,368	107,605	152,579	20,627	10,024	423,205

	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU
24-month	34,825	42,568	26,710	109,908	133,453	11,953	32,720
Month	Jun-10	Jun-10	Jun-10	Jun-10	Jun-10	Jun-10	Jun-10
Hours per month	720	720	720	720	720	720	720

[1] Conservatively used the highest crude throughput month (June 2010) for the capable of accommodating (demand growth) analysis for both the target heaters and ancillary units. However, the highest crude throughput month does not coincide with the highest firing month for the target heaters (January 2010).

PES Refinery
Heater Firing Rate Increase Plan Approval
Total Crude Charge

Month [1]	GP - 137 MBbl/month	PB - 210 MBbl/month	Total MBbl/month	Days/month	Total MBbl/day
Jan-10	5602	3987	9589	31	309.31
Feb-10	4930	3451	8382	28	299.35
Mar-10	5304	3700	9004	31	290.45
Apr-10	5530	3797	9327	30	310.89
May-10	5660	4114	9774	31	315.28
Jun-10	5313	4183	9496	30	316.54
Jul-10	5548	4116	9664	31	311.74
Aug-10	5502	4220	9722	31	313.63
Sep-10	5160	3839	9000	30	299.99
Oct-10	4664	3834	8498	31	274.14
Nov-10	3952	3880	7832	30	261.05
Dec-10	3989	3697	7687	31	247.96
Jan-11	5314	3750	9064	31	292.39
Feb-11	1658	3254	4912	28	175.45
Mar-11	3344	3290	6634	31	214.00
Apr-11	3525	3091	6616	30	220.52
May-11	5696	3596	9292	31	299.74
Jun-11	5418	3493	8911	30	297.04
Jul-11	5801	3681	9482	31	305.87
Aug-11	5134	3364	8498	31	274.13
Sep-11	5165	3401	8566	30	285.53
Oct-11	5812	3678	9489	31	306.11
Nov-11	5408	3503	8911	30	297.02
Dec-11	5699	3562	9261	31	298.74

[1] Conservatively used the highest crude throughput month (June 2010) for the capable of accommodating (demand growth) analysis for both the target heaters and ancillary units. However, the highest crude throughput month does not coincide with the highest firing month for the target heaters (January 2010).

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Period	231-B101 HHV	865-11H1 HHV	865-11H2 HHV	210-H101 HHV	210-H201 HHV	866-12H1 HHV	868-8H101 HHV
	BTU/SCF	BTU/SCF	BTU/SCF	BTU/SCF	BTU/SCF	BTU/SCF	BTU/SCF
2010	1,063.20	1,061.85	1,061.85	1,061.85	1,061.85	1,061.85	1,116.46
2011	1,027.21	999.98	999.98	999.98	999.98	999.98	1,017.56

Source	AP-42 Chapter 1.4 ($lb/10^6$ scf) Gas					lb/MMBtu	
	PM 2010	PM 2011	CO	VOC	Lead	NO_x	SO_2
231-B101	7.6	7.6	84	5.5	0.0005	0.122	0.0019
865-11H1	7.6	7.6	84	5.5	0.0005	0.113	0.0019
865-11H2	7.6	7.6	84	5.5	0.0005	0.113	0.0020
210-H101	7.6	7.6	84	5.5	0.0005	0.089	0.0033
210-H201	7.6	7.6	84	5.5	0.0005	CEMS	0.0029
866-12H1	7.6	7.6	84	5.5	0.0005	0.113	0.0022
868-H101	7.6	7.6	84	5.5	0.0005	0.113	0.0026

Source	40 CFR 98 Emission factors (kg/MMBtu)			kg/MMBtu								lb/MMBtu	
	CO_2	CH_4	N_2O	2010 Adjusted CO_2 factor	2010 Adjusted CH_4 factor	2010 Adjusted N_2O factor	2010 Adjusted CO_2e factor	2011 Adjusted CO_2 factor	2011 Adjusted CH_4 factor	2011 Adjusted N_2O factor	2011 Adjusted CO_2e factor	2010 Adjusted CO_2e factor	2011 Adjusted CO_2e factor
231-B101	53.02	0.001	0.0001	51.3	0.001	0.0001	51.3	53.1	0.001	0.0001	53.1	113.1	117.1
865-11H1	53.02	0.001	0.0001	51.3	0.001	0.0001	51.4	54.5	0.001	0.0001	54.6	113.3	120.3
865-11H2	53.02	0.001	0.0001	51.3	0.001	0.0001	51.4	54.5	0.001	0.0001	54.6	113.3	120.3
210-H101	53.02	0.001	0.0001	51.3	0.001	0.0001	51.4	54.5	0.001	0.0001	54.6	113.3	120.3
210-H201	53.02	0.001	0.0001	51.3	0.001	0.0001	51.4	54.5	0.001	0.0001	54.6	113.3	120.3
866-12H1	53.02	0.001	0.0001	51.3	0.001	0.0001	51.4	54.5	0.001	0.0001	54.6	113.3	120.3
868-H101	53.02	0.001	0.0001	48.8	0.001	0.0001	48.9	53.6	0.001	0.0001	53.6	107.7	118.2

	40 CFR 98 Defaults		
GWP	CO_2	CH_4	N_2O
	1	21	310
Default natural gas HHV (MMBtu/scf)	0.001028		

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	PM (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
Jan-10	0.15	0.17	0.12	0.44	0.60	0.06	0.12	1.67
Feb-10	0.13	0.16	0.11	0.40	0.52	0.07	0.11	1.51
Mar-10	0.17	0.09	0.07	0.41	0.53	0.04	0.11	1.42
Apr-10	0.15	0.15	0.11	0.42	0.49	0.05	0.10	1.47
May-10	0.15	0.17	0.11	0.40	0.50	0.04	0.12	1.50
Jun-10	0.12	0.15	0.10	0.39	0.48	0.04	0.11	1.40
Jul-10	0.12	0.16	0.10	0.41	0.48	0.05	0.08	1.39
Aug-10	0.16	0.16	0.12	0.42	0.58	0.05	0.12	1.60
Sep-10	0.15	0.14	0.11	0.39	0.51	0.05	0.07	1.41
Oct-10	0.13	0.16	0.12	0.43	0.49	0.08	0.09	1.50
Nov-10	0.13	0.14	0.12	0.42	0.51	0.01	0.12	1.45
Dec-10	0.14	0.12	0.12	0.43	0.48	0.04	0.12	1.44
Jan-11	0.17	0.15	0.12	0.45	0.50	0.05	0.13	1.57
Feb-11	0.03	0.14	0.11	0.42	0.46	0.05	0.12	1.32
Mar-11	0.02	0.05	0.04	0.49	0.44	0.06	0.10	1.19
Apr-11	0.11	0.01	0.03	0.47	0.40	0.02	0.08	1.10
May-11	0.18	0.16	0.12	0.44	0.46	0.04	0.09	1.51
Jun-11	0.14	0.15	0.12	0.44	0.44	0.03	0.09	1.41
Jul-11	0.16	0.15	0.11	0.45	0.42	0.04	0.10	1.44
Aug-11	0.16	0.16	0.12	0.47	0.34	0.05	0.11	1.40
Sep-11	0.15	0.15	0.12	0.41	0.46	0.06	0.08	1.45
Oct-11	0.19	0.15	0.12	0.45	0.57	0.06	0.10	1.64
Nov-11	0.18	0.18	0.12	0.44	0.54	0.08	0.05	1.60
Dec-11	0.18	0.19	0.13	0.41	0.58	0.08	0.04	1.60

	PM (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
2010	1.70	1.78	1.29	4.97	6.16	0.57	1.28	17.75
2011	1.65	1.63	1.25	5.34	5.62	0.62	1.11	17.22
2010-2011 average	1.68	1.71	1.27	5.15	5.89	0.60	1.19	17.48

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	CO (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
Jan-10	1.67	1.89	1.35	4.92	6.62	0.70	1.35	18.51
Feb-10	1.39	1.82	1.26	4.46	5.76	0.73	1.23	16.64
Mar-10	1.84	1.01	0.76	4.53	5.89	0.44	1.20	15.67
Apr-10	1.71	1.70	1.19	4.63	5.37	0.51	1.14	16.23
May-10	1.71	1.89	1.18	4.47	5.50	0.47	1.37	16.59
Jun-10	1.38	1.68	1.06	4.35	5.28	0.47	1.23	15.45
Jul-10	1.35	1.81	1.09	4.49	5.25	0.53	0.90	15.41
Aug-10	1.73	1.71	1.27	4.59	6.39	0.60	1.35	17.66
Sep-10	1.70	1.51	1.18	4.33	5.59	0.54	0.75	15.60
Oct-10	1.48	1.75	1.31	4.71	5.45	0.83	1.00	16.53
Nov-10	1.38	1.56	1.31	4.67	5.67	0.08	1.33	16.00
Dec-10	1.50	1.34	1.28	4.75	5.30	0.41	1.30	15.88
Jan-11	1.87	1.69	1.32	4.93	5.53	0.53	1.48	17.35
Feb-11	0.32	1.50	1.22	4.68	5.04	0.51	1.35	14.62
Mar-11	0.17	0.50	0.42	5.38	4.89	0.64	1.13	13.13
Apr-11	1.17	0.06	0.30	5.17	4.40	0.19	0.91	12.21
May-11	1.94	1.82	1.37	4.90	5.14	0.45	1.03	16.65
Jun-11	1.53	1.61	1.27	4.86	4.86	0.38	1.04	15.54
Jul-11	1.73	1.63	1.23	5.00	4.67	0.47	1.12	15.86
Aug-11	1.74	1.72	1.28	5.19	3.72	0.58	1.24	15.46
Sep-11	1.71	1.67	1.34	4.55	5.14	0.71	0.90	16.01
Oct-11	2.11	1.64	1.34	4.93	6.27	0.71	1.11	18.11
Nov-11	1.96	2.03	1.37	4.92	6.02	0.84	0.51	17.65
Dec-11	1.96	2.14	1.40	4.52	6.41	0.87	0.41	17.71

	CO (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
2010	18.83	19.68	14.25	54.89	68.07	6.31	14.14	196.16
2011	18.20	18.04	13.87	59.01	62.07	6.88	12.23	190.30
2010-2011 average	18.52	18.86	14.06	56.95	65.07	6.60	13.18	193.23

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	VOC (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
Jan-10	0.11	0.12	0.09	0.32	0.43	0.05	0.09	1.21
Feb-10	0.09	0.12	0.08	0.29	0.38	0.05	0.08	1.09
Mar-10	0.12	0.07	0.05	0.30	0.39	0.03	0.08	1.03
Apr-10	0.11	0.11	0.08	0.30	0.35	0.03	0.07	1.06
May-10	0.11	0.12	0.08	0.29	0.36	0.03	0.09	1.09
Jun-10	0.09	0.11	0.07	0.28	0.35	0.03	0.08	1.01
Jul-10	0.09	0.12	0.07	0.29	0.34	0.03	0.06	1.01
Aug-10	0.11	0.11	0.08	0.30	0.42	0.04	0.09	1.16
Sep-10	0.11	0.10	0.08	0.28	0.37	0.04	0.05	1.02
Oct-10	0.10	0.11	0.09	0.31	0.36	0.05	0.07	1.08
Nov-10	0.09	0.10	0.09	0.31	0.37	0.01	0.09	1.05
Dec-10	0.10	0.09	0.08	0.31	0.35	0.03	0.09	1.04
Jan-11	0.12	0.11	0.09	0.32	0.36	0.03	0.10	1.14
Feb-11	0.02	0.10	0.08	0.31	0.33	0.03	0.09	0.96
Mar-11	0.01	0.03	0.03	0.35	0.32	0.04	0.07	0.86
Apr-11	0.08	0.00	0.02	0.34	0.29	0.01	0.06	0.80
May-11	0.13	0.12	0.09	0.32	0.34	0.03	0.07	1.09
Jun-11	0.10	0.11	0.08	0.32	0.32	0.02	0.07	1.02
Jul-11	0.11	0.11	0.08	0.33	0.31	0.03	0.07	1.04
Aug-11	0.11	0.11	0.08	0.34	0.24	0.04	0.08	1.01
Sep-11	0.11	0.11	0.09	0.30	0.34	0.05	0.06	1.05
Oct-11	0.14	0.11	0.09	0.32	0.41	0.05	0.07	1.19
Nov-11	0.13	0.13	0.09	0.32	0.39	0.05	0.03	1.16
Dec-11	0.13	0.14	0.09	0.30	0.42	0.06	0.03	1.16

	VOC (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
2010	1.23	1.29	0.93	3.59	4.46	0.41	0.93	12.84
2011	1.19	1.18	0.91	3.86	4.06	0.45	0.80	12.46
2010-2011 average	1.21	1.23	0.92	3.73	4.26	0.43	0.86	12.65

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	NOx (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
Jan-10	2.58	2.70	1.93	5.53	2.44	1.00	2.03	18.21
Feb-10	2.14	2.60	1.80	5.02	1.99	1.04	1.85	16.44
Mar-10	2.83	1.45	1.09	5.10	1.78	0.63	1.80	14.68
Apr-10	2.64	2.42	1.69	5.21	1.51	0.73	1.71	15.90
May-10	2.63	2.70	1.69	5.02	1.41	0.68	2.05	16.19
Jun-10	2.12	2.41	1.51	4.89	1.41	0.68	1.85	14.87
Jul-10	2.08	2.58	1.56	5.05	1.41	0.76	1.35	14.79
Aug-10	2.68	2.45	1.82	5.17	1.98	0.86	2.03	16.97
Sep-10	2.62	2.15	1.68	4.87	1.72	0.77	1.13	14.96
Oct-10	2.28	2.50	1.88	5.30	1.65	1.19	1.50	16.29
Nov-10	2.14	2.23	1.87	5.25	1.87	0.11	1.99	15.46
Dec-10	2.32	1.91	1.83	5.34	1.57	0.58	1.95	15.51
Jan-11	2.80	2.27	1.77	5.22	1.45	0.71	2.02	16.25
Feb-11	0.47	2.02	1.65	4.96	1.08	0.68	1.85	12.71
Mar-11	0.25	0.68	0.56	5.70	1.39	0.87	1.55	10.99
Apr-11	1.74	0.09	0.41	5.47	1.33	0.26	1.25	10.55
May-11	2.89	2.45	1.84	5.19	1.60	0.60	1.41	15.99
Jun-11	2.28	2.17	1.71	5.15	1.52	0.51	1.42	14.76
Jul-11	2.58	2.19	1.66	5.30	1.60	0.64	1.53	15.50
Aug-11	2.60	2.31	1.72	5.50	1.23	0.78	1.70	15.83
Sep-11	2.55	2.25	1.80	4.82	2.28	0.96	1.23	15.88
Oct-11	3.14	2.21	1.81	5.22	2.19	0.96	1.52	17.04
Nov-11	2.93	2.74	1.84	5.21	1.84	1.13	0.69	16.38
Dec-11	2.93	2.88	1.89	4.79	1.90	1.17	0.57	16.12

	NOx (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
2010	29.08	28.11	20.35	61.75	20.72	9.02	21.23	190.26
2011	27.15	24.27	18.66	62.52	19.41	9.26	16.74	178.01
2010-2011 average	28.12	26.19	19.50	62.14	20.07	9.14	18.99	184.14

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	SO_2 (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
Jan-10	0.06	0.01	0.01	0.03	0.05	0.01	0.03	0.20
Feb-10	0.03	0.02	0.01	0.04	0.05	0.01	0.03	0.19
Mar-10	0.01	0.02	0.01	0.57	0.59	0.08	0.03	1.31
Apr-10	0.02	0.02	0.02	0.07	0.08	0.01	0.02	0.23
May-10	0.02	0.04	0.03	0.10	0.12	0.01	0.03	0.35
Jun-10	0.03	0.04	0.02	0.09	0.11	0.01	0.03	0.33
Jul-10	0.02	0.03	0.02	0.06	0.07	0.01	0.03	0.24
Aug-10	0.03	0.10	0.07	0.26	0.36	0.03	0.04	0.89
Sep-10	0.03	0.08	0.06	0.23	0.29	0.03	0.02	0.75
Oct-10	0.01	0.05	0.04	0.13	0.16	0.02	0.02	0.45
Nov-10	0.01	0.03	0.02	0.08	0.09	0.00	0.07	0.30
Dec-10	0.01	0.02	0.02	0.08	0.09	0.01	0.04	0.28
Jan-11	0.00	0.04	0.03	0.12	0.14	0.01	0.03	0.38
Feb-11	0.00	0.06	0.05	0.19	0.21	0.02	0.04	0.57
Mar-11	0.00	0.03	0.02	0.28	0.25	0.04	0.04	0.66
Apr-11	0.00	0.00	0.01	0.91	0.74	0.01	0.03	1.70
May-11	0.02	0.03	0.02	0.07	0.08	0.01	0.02	0.25
Jun-11	0.07	0.06	0.05	0.18	0.18	0.01	0.07	0.62
Jul-11	0.06	0.04	0.03	0.13	0.12	0.01	0.06	0.45
Aug-11	0.05	0.03	0.02	0.11	0.06	0.02	0.04	0.33
Sep-11	0.03	0.03	0.03	0.09	0.11	0.01	0.03	0.33
Oct-11	0.03	0.03	0.03	0.10	0.12	0.01	0.02	0.34
Nov-11	0.07	0.02	0.02	0.06	0.07	0.01	0.01	0.26
Dec-11	0.07	0.03	0.02	0.06	0.09	0.01	0.01	0.29

	SO_2 (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
2010	0.28	0.45	0.33	1.75	2.06	0.23	0.40	5.50
2011	0.41	0.42	0.33	2.30	2.16	0.18	0.39	6.19
2010-2011 average	0.35	0.43	0.33	2.02	2.11	0.20	0.39	5.85

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	Lead (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
Jan-10	1.0E-05	1.1E-05	8.0E-06	2.9E-05	3.9E-05	4.2E-06	8.0E-06	1.1E-04
Feb-10	8.3E-06	1.1E-05	7.5E-06	2.7E-05	3.4E-05	4.3E-06	7.3E-06	9.9E-05
Mar-10	1.1E-05	6.0E-06	4.6E-06	2.7E-05	3.5E-05	2.6E-06	7.1E-06	9.3E-05
Apr-10	1.0E-05	1.0E-05	7.1E-06	2.8E-05	3.2E-05	3.0E-06	6.8E-06	9.7E-05
May-10	1.0E-05	1.1E-05	7.1E-06	2.7E-05	3.3E-05	2.8E-06	8.1E-06	9.9E-05
Jun-10	8.2E-06	1.0E-05	6.3E-06	2.6E-05	3.1E-05	2.8E-06	7.3E-06	9.2E-05
Jul-10	8.0E-06	1.1E-05	6.5E-06	2.7E-05	3.1E-05	3.1E-06	5.4E-06	9.2E-05
Aug-10	1.0E-05	1.0E-05	7.6E-06	2.7E-05	3.8E-05	3.6E-06	8.0E-06	1.1E-04
Sep-10	1.0E-05	9.0E-06	7.0E-06	2.6E-05	3.3E-05	3.2E-06	4.5E-06	9.3E-05
Oct-10	8.8E-06	1.0E-05	7.8E-06	2.8E-05	3.2E-05	4.9E-06	5.9E-06	9.8E-05
Nov-10	8.2E-06	9.3E-06	7.8E-06	2.8E-05	3.4E-05	4.7E-07	7.9E-06	9.5E-05
Dec-10	8.9E-06	8.0E-06	7.6E-06	2.8E-05	3.2E-05	2.4E-06	7.7E-06	9.5E-05
Jan-11	1.1E-05	1.0E-05	7.9E-06	2.9E-05	3.3E-05	3.1E-06	8.8E-06	1.0E-04
Feb-11	1.9E-06	8.9E-06	7.3E-06	2.8E-05	3.0E-05	3.0E-06	8.1E-06	8.7E-05
Mar-11	9.9E-07	3.0E-06	2.5E-06	3.2E-05	2.9E-05	3.8E-06	6.7E-06	7.8E-05
Apr-11	6.9E-06	3.9E-07	1.8E-06	3.1E-05	2.6E-05	1.2E-06	5.4E-06	7.3E-05
May-11	1.2E-05	1.1E-05	8.2E-06	2.9E-05	3.1E-05	2.7E-06	6.2E-06	9.9E-05
Jun-11	9.1E-06	9.6E-06	7.6E-06	2.9E-05	2.9E-05	2.2E-06	6.2E-06	9.3E-05
Jul-11	1.0E-05	9.7E-06	7.3E-06	3.0E-05	2.8E-05	2.8E-06	6.7E-06	9.4E-05
Aug-11	1.0E-05	1.0E-05	7.6E-06	3.1E-05	2.2E-05	3.5E-06	7.4E-06	9.2E-05
Sep-11	1.0E-05	1.0E-05	8.0E-06	2.7E-05	3.1E-05	4.2E-06	5.3E-06	9.5E-05
Oct-11	1.3E-05	9.8E-06	8.0E-06	2.9E-05	3.7E-05	4.2E-06	6.6E-06	1.1E-04
Nov-11	1.2E-05	1.2E-05	8.2E-06	2.9E-05	3.6E-05	5.0E-06	3.0E-06	1.1E-04
Dec-11	1.2E-05	1.3E-05	8.3E-06	2.7E-05	3.8E-05	5.2E-06	2.5E-06	1.1E-04

	Lead (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
2010	1.1E-04	1.2E-04	8.5E-05	3.3E-04	4.1E-04	3.8E-05	8.4E-05	1.2E-03
2011	1.1E-04	1.1E-04	8.3E-05	3.5E-04	3.7E-04	4.1E-05	7.3E-05	1.1E-03
2010-2011 average	1.1E-04	1.1E-04	8.4E-05	3.4E-04	3.9E-04	3.9E-05	7.8E-05	1.2E-03

PES Refinery
Heater Firing Rate Increase Plan Approval
Target Heater Monthly Emissions

	CO_2e (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
Jan-10	2,397	2,706	1,934	7,038	9,485	1,006	1,931	26,498
Feb-10	1,986	2,604	1,805	6,387	8,247	1,039	1,764	23,830
Mar-10	2,628	1,453	1,095	6,487	8,433	628	1,716	22,440
Apr-10	2,445	2,429	1,697	6,626	7,686	732	1,628	23,243
May-10	2,442	2,710	1,697	6,394	7,873	678	1,956	23,750
Jun-10	1,970	2,411	1,513	6,225	7,558	677	1,762	22,116
Jul-10	1,933	2,585	1,562	6,424	7,518	758	1,291	22,070
Aug-10	2,483	2,455	1,822	6,577	9,154	863	1,931	25,285
Sep-10	2,431	2,160	1,689	6,204	8,010	774	1,075	22,343
Oct-10	2,119	2,508	1,882	6,743	7,803	1,189	1,428	23,672
Nov-10	1,982	2,239	1,872	6,684	8,117	114	1,898	22,907
Dec-10	2,152	1,917	1,833	6,803	7,587	580	1,860	22,733
Jan-11	2,683	2,421	1,889	7,058	7,915	758	2,114	24,839
Feb-11	454	2,149	1,752	6,702	7,214	724	1,937	20,934
Mar-11	239	722	595	7,705	6,999	921	1,622	18,802
Apr-11	1,671	93	434	7,397	6,299	277	1,306	17,477
May-11	2,771	2,610	1,964	7,016	7,355	642	1,480	23,838
Jun-11	2,188	2,311	1,823	6,956	6,953	539	1,486	22,255
Jul-11	2,481	2,334	1,768	7,157	6,691	680	1,602	22,713
Aug-11	2,496	2,460	1,828	7,427	5,324	831	1,777	22,143
Sep-11	2,446	2,398	1,913	6,512	7,357	1,018	1,284	22,928
Oct-11	3,015	2,349	1,926	7,057	8,975	1,021	1,586	25,929
Nov-11	2,808	2,913	1,964	7,041	8,621	1,201	726	25,274
Dec-11	2,808	3,069	2,007	6,471	9,176	1,241	592	25,365

	CO_2e (TPY)							
	231-B101	865-11H1	865-11H2	210-H101	210-H201	866-12H1	868-8H101	Total
2010	26,968	28,176	20,400	78,591	97,470	9,039	20,242	280,887
2011	26,062	25,830	19,861	84,501	88,878	9,853	17,512	272,496
2010-2011 average	26,515	27,003	20,131	81,546	93,174	9,446	18,877	276,692

PES Refinery
Heater Firing Rate Increase Plan Approval
Target Heater SO_2 Emissions

Month	Unit 231-B101	Unit 865-11H1	Unit 865-11H2	Unit 210-H101	Unit 210-H201	Unit 866-12H1	Unit 868-8H101
	SO_2, pounds	SO_2, pounds	SO_2, pounds	SO_2, pounds	SO_2, pounds	SO_2, pounds	SO_2, pounds
Jan-10	115.62	28.68	19.46	69.14	90.92	10.19	69.19
Feb-10	62.47	31.02	22.16	78.31	104.99	12.54	59.53
Mar-10	21.10	31.78	25.45	1145.24	1177.73	165.60	59.07
Apr-10	34.22	47.17	33.19	130.91	152.81	13.41	49.36
May-10	39.74	86.65	53.97	193.65	237.08	23.04	56.72
Jun-10	51.43	70.43	44.39	183.89	221.00	19.97	61.95
Jul-10	44.54	50.86	33.40	125.88	144.94	15.35	61.34
Aug-10	51.17	194.10	144.96	521.67	726.90	67.99	75.29
Sep-10	69.51	159.49	126.53	464.22	577.50	55.28	47.80
Oct-10	27.48	103.74	75.17	268.43	317.77	49.06	49.03
Nov-10	27.93	54.66	44.48	150.13	187.08	1.76	136.81
Dec-10	16.88	45.25	44.63	167.56	185.73	16.84	74.96
Jan-11	3.04	87.29	66.89	243.78	279.18	26.14	55.15
Feb-11	0.76	122.61	98.17	376.82	411.41	41.22	87.95
Mar-11	4.32	54.66	47.95	553.88	492.18	77.93	86.03
Apr-11	9.58	2.31	18.13	1810.99	1475.46	19.87	58.01
May-11	48.68	60.10	40.29	140.75	158.92	11.91	38.66
Jun-11	133.76	121.80	96.13	363.20	362.81	28.59	134.76
Jul-11	118.26	83.45	63.41	254.23	240.79	23.85	110.59
Aug-11	107.58	58.33	43.48	218.54	124.43	30.20	80.02
Sep-11	61.12	69.72	55.94	189.19	212.47	29.29	50.75
Oct-11	63.82	63.23	52.19	190.95	239.08	27.98	47.79
Nov-11	137.18	49.02	33.63	120.99	149.00	21.85	12.95
Dec-11	138.27	61.20	39.39	129.90	182.13	25.86	12.08
2011 SO_2 EF (lb/MMBtu)[1]	0.00186	0.00194	0.00199	0.00327	0.00293	0.00223	0.00261

[1] The target heaters only became subject to refinery fuel gas sulfur limits required by New Source Performance Standards Subpart J for Petroleum Refineries in 2011. Therefore, for this plan approval, the 2011 actual SO_2 emissions and 2011 actual fired rates for the each target heater were used to derive a heater-specific SO_2 emission factor.

PES Refinery
Heater Firing Rate Increase Plan Approval
Emission Estimates for Ancillary
Upstream/Downstream Units

Crude Increase Basis

Crude Unit	24-month Actual Rate (MBPD)	Capable Rate - June 2010 (MBPD)	Capable increase from baseline (%)	Future Projected Actual Rate (MBPD)	Expected increase from this plan approval (%)
TOTAL	**284.4**	**316.5**	**111%**	**346.0**	**122%**

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Source	2010 ACTUAL EMISSIONS (TPY)					2011 ACTUAL EMISSIONS (TPY)					2010-11 Baseline Actual Emissions (TPY)				
	VOC	SOx	NOx	CO	PM	VOC	SOx	NOx	CO	PM	VOC	SOx	NOx	CO	PM
TANKS*	176.09	-	-	-	-	159.95	-	-	-	-	168.02	-	-	-	-
SRTF TANKS*	66.79	-	-	-	-	68.38	-	-	-	-	67.58	-	-	-	-
WWTP	61.53	-	-	-	-	51.64	-	-	-	-	56.58	-	-	-	-
SRTF WWTP	0.93	-	-	-	-	2.29	-	-	-	-	1.61	-	-	-	-
GP BARGE LOADING (MVRU)	8.34	-	35.28	2.05	0.31	8.28	-	36.89	2.15	0.32	8.31	-	36.08	2.10	0.31
PB WHARF	31.51	-	-	-	-	40.17	-	-	-	-	35.84	-	-	-	-
GP BUTANE/PP LOADING	1.03	-	-	-	-	1.04	-	-	-	-	1.04	-	-	-	-
Sulfur Recovery Unit	-	14.11	4.36	171.33	-	-	10.37	4.83	189.98	-	-	12.24	4.59	180.66	-
Total Increases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Calculation Formula											= Average(A,F)	= Average(B,G)	= Average(C,H)	= Average(D,I)	= Average(E,J)

*** For Tanks working losses are approximately 4% of emissions and will increase by throughput change:**

Expected increases for plan approval from tanks = 0.96 + .04*1.22 = 1.009

Capable increases from baseline for tanks = 0.96 + .04*1.11 = 1.005

**** Only capable % increases that are greater than zero are subtracted from the expected % increases.**

Note: 868 and 1232 FCCUs are generally operated at optimal rates and feed purchased (or transferred from MH) in 2010-11 will be replaced by increased production at 137 and 210 and should therefore show no significant change in emissions in the future.

PES Refinery
Heater Firing Rate Increase Plan Approval
Emission Estimates for Ancillary
Upstream/Downstream Units

	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Source	Expected increases from this plan approval (%)					Capable increases from baseline (%)					Projected Future Actual Emissions (TPY)				
	VOC	SOx	NOx	CO	PM	VOC	SOx	NOx	CO	PM	VOC	SOx	NOx	CO	PM
TANKS*	0.87%	-	-	-	-	0.45%	-	-	-	-	169.47	-	-	-	-
SRTF TANKS*	0.87%	-	-	-	-	0.45%	-	-	-	-	68.17	-	-	-	-
WWTP	22%	-	-	-	-	11%	-	-	-	-	68.84	-	-	-	-
SRTF WWTP	22%	-	-	-	-	11%	-	-	-	-	1.96	-	-	-	-
GP BARGE LOADING (MVRU)	22%	-	22%	22%	22%	11%	-	11%	11%	11%	10.11	-	43.90	2.55	0.38
PB WHARF	22%	-	-	-	-	11%	-	-	-	-	43.60	-	-	-	-
GP BUTANE/PP LOADING	22%	-	-	-	-	11%	-	-	-	-	1.26	-	-	-	-
Sulfur Recovery Unit	-	22%	22%	22%	-	-	11%	11%	11%	-	-	14.89	5.59	219.79	-
Total Increases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Calculation Formula											= K * (1+P)	= L * (1+Q)	= M * (1+R)	= N * (1+S)	= O * (1+T)

PES Refinery
Heater Firing Rate Increase Plan Approval
Emission Estimates for Ancillary
Upstream/Downstream Units

	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN
Source	Capable of Accommodating Emissions (TPY)**					Emissions Increases from Plan Approval (TPY)				
	VOC	SOx	NOx	CO	PM	VOC	SOx	NOx	CO	PM
TANKS*	168.78					0.70	-	-	-	-
SRTF TANKS*	67.89					0.28	-	-	-	-
WWTP	62.98					5.86	-	-	-	-
SRTF WWTP	1.79					0.17	-	-	-	-
GP BARGE LOADING (MVRU)	9.25		40.16	2.34	0.35	0.86	-	3.74	0.22	0.03
PB WHARF	39.89					3.71	-	-	-	-
GP BUTANE/PP LOADING	1.15					0.11	-	-	-	-
Sulfur Recovery Unit		13.62	5.11	201.08		-	1.27	0.48	18.71	-
Total Increases						11.68	1.27	4.21	18.93	0.03
Calculation Formula	= K * (1+U)	= L * (1+V)	= M * (1+W)	= N * (1+X)	= O * (1+Y)	= (Z - K) - (AE - K)	= (AA - L) - (AF - L)	= (AB - M) - (AG - M)	= (AC - N) - (AH - N)	= (AD - O) - (AI - O)

PES Refinery

Heater Firing Rate Increase Plan Approval

Emission Estimates for Ancillary Upstream/Downstream Unmodified Heaters/Boiler

Crude Increase Basis

Crude Unit	24-month Actual Rate (MBPD)	Capable Rate - June 2010 (MBPD)	Capable increase from baseline (%)	Future Projected Actual Rate (MBPD)	Expected increase from this plan approval (%)
TOTAL	**284.4**	**316.5**	**111%**	**346.0**	**122%**

		A	B	C	D	E	F	G	H	I	J	K	L
Unit	Heater	2010 ACTUAL EMISSIONS (TPY)						2011 ACTUAL EMISSIONS (TPY)					
		SOx	NOx	CO	PM	VOC	Lead	SOx	NOx	CO	PM	VOC	Lead
137	F-1	3.88	209.56	120.36	2.72	7.88	7.1E-04	8.02	179.81	117.59	10.64	7.70	7.2E-04
137	F-2	0.86	48.73	26.70	0.60	1.75	1.6E-04	1.33	37.33	24.06	2.18	1.58	1.5E-04
137	F-3	0.41	6.91	12.20	0.28	0.80	7.3E-05	0.65	6.42	11.61	1.05	0.76	7.2E-05
210	13H-1	1.60	87.40	52.40	1.18	3.43	3.1E-04	1.87	83.80	50.30	4.55	3.30	3.4E-04
1332	H-400**	2.25	67.10	40.10	0.91	2.62	2.4E-04	1.27	14.00	46.17	4.18	3.02	2.8E-04
1332	H-401**	2.73	83.10	49.80	1.13	3.26	3.0E-04	1.69	17.84	62.19	5.63	4.07	3.7E-04
1332	H-601	0.43	4.03	6.69	0.15	0.44	4.0E-05	0.20	4.78	7.83	0.71	0.51	4.8E-05
1332	H-602	0.66	7.62	12.80	0.29	0.84	7.6E-05	0.44	9.30	15.53	1.41	1.02	9.3E-05
1332	H-1	0.05	0.03	0.05	0.00	0.00	3.1E-07	0.00	0.22	0.36	0.03	0.02	2.2E-06
1332	H-2	0.52	4.25	1.37	0.25	0.71	6.2E-05	0.25	4.98	1.61	1.19	0.86	7.8E-05
1332	H-3	0.39	3.88	6.48	0.15	0.42	3.9E-05	0.25	5.43	9.03	0.82	0.59	5.4E-05
860	2H2	0.40	8.71	14.30	0.32	0.94	8.7E-05	0.38	8.47	12.60	1.14	0.82	8.5E-05
860	2H3	1.01	61.60	36.20	0.82	2.37	2.2E-04	1.02	64.20	34.00	3.08	2.23	2.3E-04
860	2H4	0.52	11.40	18.70	0.42	1.23	1.1E-04	0.50	11.70	17.40	1.58	1.14	1.2E-04
860	2H5	1.13	69.60	40.80	0.92	2.67	2.5E-04	1.05	65.70	34.90	3.16	2.28	2.3E-04
860	2H7	0.42	9.24	15.20	0.34	1.00	9.2E-05	0.38	8.31	12.40	1.12	0.81	8.3E-05
860	2H8	0.01	7.80	12.60	0.29	0.82	7.8E-05	0.19	6.92	11.10	1.01	0.73	6.8E-05
864	PH1	0.45	9.17	14.80	0.34	0.97	9.2E-05	0.34	8.02	13.70	1.24	0.90	4.5E-05
864	PH7	0.23	4.70	7.62	0.17	0.50	4.7E-05	0.18	4.49	7.71	0.70	0.51	7.4E-05
864	PH11	0.44	8.91	14.40	0.33	0.95	8.9E-05	0.30	7.44	12.80	1.16	0.84	6.6E-05
864	PH12	0.37	7.59	12.30	0.28	0.80	7.6E-05	0.28	6.61	11.40	1.03	0.74	1.1E-04
859	1H1	0.44	6.98	9.98	0.62	1.81	1.7E-04	0.79	5.44	7.77	2.07	1.49	0.0E+00
870	H-01	0.05	4.09	5.29	0.88	0.06	1.5E-05	0.11	4.07	0.03	0.88	0.06	2.2E-05
433	H-1	2.43	24.97	42.40	0.96	2.77	2.5E-04	1.30	14.98	55.66	5.04	3.64	3.4E-04
1232	B-104	0.01	0.29	0.45	0.01	0.03	2.9E-06	0.09	0.99	1.69	0.15	0.11	9.8E-06
870	H-02	0.23	4.22	0.08	0.38	0.14	7.1E-05	0.36	3.63	0.03	0.33	0.12	6.7E-05
	Calculation Formula												
	Heater Total	21.92	761.88	574.07	14.74	39.20	3.7E-03	23.24	584.87	579.46	56.04	39.85	3.7E-03
	No. 3 Boilerhouse	12.91	199.60	316.24	9.24	20.69	2.3E-03	6.69	156.54	330.38	29.89	21.63	1.9E-03
	Calculation Formula												
	Heater/Boiler Total	34.82	961.48	890.31	23.98	59.89	6.0E-03	29.93	741.41	909.84	85.93	61.48	5.7E-03

*** Only capable % increases that are greater than zero are subtracted from the expected % increases.**

**** Future projected emissions are only based on 2011 actual emissions because of the SCR install in January 2011**

PES Refinery
Heater Firing Rate Increase Plan Approval
Emission Estimates for Ancillary
Upstream/Downstream Unmodified
Heaters/Boiler

		M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
Unit	Heater	2010-11 Baseline Actual Emissions (TPY)						Expected increases from this plan						Capable increases from baseline (%)					
		SOx	NOx	CO	PM	VOC	Lead	SOx	NOx	CO	PM	VOC	Lead	SOx	NOx	CO	PM	VOC	Lead
137	F-1	5.95	194.69	118.97	6.68	7.79	7.2E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
137	F-2	1.10	43.03	25.38	1.39	1.67	1.5E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
137	F-3	0.53	6.67	11.91	0.66	0.78	7.2E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
210	13H-1	1.73	85.60	51.35	2.87	3.37	3.3E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1332	H-400**	1.27	14.00	46.17	4.18	3.02	2.8E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1332	H-401**	1.69	17.84	62.19	5.63	4.07	3.7E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1332	H-601	0.31	4.41	7.26	0.43	0.48	4.4E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1332	H-602	0.55	8.46	14.17	0.85	0.93	8.5E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1332	H-1	0.03	0.12	0.20	0.02	0.01	1.2E-06	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1332	H-2	0.38	4.62	1.49	0.72	0.78	7.0E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1332	H-3	0.32	4.66	7.76	0.48	0.51	4.7E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
860	2H2	0.39	8.59	13.45	0.73	0.88	8.6E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
860	2H3	1.01	62.90	35.10	1.95	2.30	2.2E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
860	2H4	0.51	11.55	18.05	1.00	1.19	1.2E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
860	2H5	1.09	67.65	37.85	2.04	2.48	2.4E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
860	2H7	0.40	8.78	13.80	0.73	0.90	8.8E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
860	2H8	0.10	7.36	11.85	0.65	0.78	7.3E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
864	PH1	0.39	8.60	14.25	0.79	0.94	6.8E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
864	PH7	0.21	4.60	7.67	0.43	0.50	6.1E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
864	PH11	0.37	8.18	13.60	0.74	0.89	7.8E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
864	PH12	0.32	7.10	11.85	0.65	0.77	9.0E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
859	1H1	0.62	6.21	8.88	1.35	1.65	8.3E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
870	H-01	0.08	4.08	2.66	0.88	0.06	1.9E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
433	H-1	1.86	19.98	49.03	3.00	3.21	2.9E-04	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
1232	B-104	0.05	0.64	1.07	0.08	0.07	6.4E-06	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
870	H-02	0.30	3.93	0.06	0.36	0.13	6.9E-05	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
	Calculation Formula	= Average(A,G)	= Average(B,H)	= Average(C,I)	= Average(D,J)	= Average(E,K)	= Average(F,L)												
	Heater Total	21.57	614.20	586.00	39.27	40.13	3.8E-03												
	No. 3 Boilerhouse	9.80	178.07	323.31	19.57	21.16	2.1E-03	22%	22%	22%	22%	22%	22%	11%	11%	11%	11%	11%	11%
	Calculation Formula	= Average(A,G)	= Average(B,H)	= Average(C,I)	= Average(D,J)	= Average(E,K)	= Average(F,L)												
	Heater/Boiler Total	31.37	792.26	909.31	58.84	61.29	5.9E-03												

PES Refinery
Heater Firing Rate Increase Plan Approval
Emission Estimates for Ancillary
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Heaters/Boiler

		AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP
Unit	Heater	Projected Future Actual Emissions (TPY)						Capable of Accommodating Emissions (TPY)*					
		SOx	NOx	CO	PM	VOC	Lead	SOx	NOx	CO	PM	VOC	Lead
137	F-1	7.24	236.86	144.74	8.13	9.48	8.7E-04	6.62	216.69	132.42	7.44	8.67	8.0E-04
137	F-2	1.33	52.35	30.88	1.69	2.03	1.9E-04	1.22	47.89	28.25	1.55	1.85	1.7E-04
137	F-3	0.65	8.11	14.48	0.81	0.95	8.8E-05	0.59	7.42	13.25	0.74	0.87	8.1E-05
210	13H-1	2.11	104.14	62.47	3.49	4.09	4.0E-04	1.93	95.28	57.15	3.19	3.75	3.6E-04
1332	H-400**	1.54	17.03	56.17	5.08	3.67	3.4E-04	1.41	15.58	51.39	4.65	3.36	3.1E-04
1332	H-401**	2.06	21.70	75.66	6.85	4.95	4.5E-04	1.88	19.86	69.22	6.27	4.53	4.1E-04
1332	H-601	0.38	5.36	8.83	0.52	0.58	5.4E-05	0.35	4.90	8.08	0.48	0.53	4.9E-05
1332	H-602	0.67	10.29	17.23	1.03	1.13	1.0E-04	0.61	9.42	15.77	0.94	1.03	9.4E-05
1332	H-1	0.03	0.15	0.25	0.02	0.02	1.5E-06	0.03	0.14	0.23	0.02	0.01	1.4E-06
1332	H-2	0.47	5.61	1.81	0.87	0.95	8.5E-05	0.43	5.14	1.66	0.80	0.87	7.8E-05
1332	H-3	0.39	5.66	9.43	0.59	0.62	5.7E-05	0.36	5.18	8.63	0.54	0.57	5.2E-05
860	2H2	0.48	10.45	16.36	0.89	1.07	1.0E-04	0.44	9.56	14.97	0.81	0.98	9.6E-05
860	2H3	1.23	76.52	42.70	2.37	2.80	2.7E-04	1.13	70.01	39.07	2.17	2.56	2.5E-04
860	2H4	0.62	14.05	21.96	1.22	1.44	1.4E-04	0.57	12.86	20.09	1.11	1.32	1.3E-04
860	2H5	1.32	82.30	46.05	2.48	3.01	2.9E-04	1.21	75.30	42.13	2.27	2.75	2.7E-04
860	2H7	0.49	10.68	16.79	0.89	1.10	1.1E-04	0.44	9.77	15.36	0.81	1.01	9.8E-05
860	2H8	0.12	8.95	14.42	0.79	0.95	8.9E-05	0.11	8.19	13.19	0.72	0.86	8.1E-05
864	PH1	0.48	10.46	17.34	0.96	1.14	8.3E-05	0.44	9.57	15.86	0.88	1.04	7.6E-05
864	PH7	0.25	5.59	9.33	0.53	0.61	7.4E-05	0.23	5.11	8.53	0.48	0.56	6.8E-05
864	PH11	0.45	9.95	16.55	0.90	1.08	9.4E-05	0.41	9.10	15.14	0.82	0.99	8.6E-05
864	PH12	0.39	8.64	14.42	0.79	0.94	1.1E-04	0.36	7.90	13.19	0.73	0.86	1.0E-04
859	1H1	0.75	7.56	10.80	1.64	2.01	1.0E-04	0.69	6.91	9.88	1.50	1.84	9.2E-05
870	H-01	0.10	4.96	3.24	1.07	0.07	2.3E-05	0.09	4.54	2.96	0.98	0.06	2.1E-05
433	H-1	2.27	24.30	59.65	3.65	3.90	3.6E-04	2.07	22.23	54.57	3.34	3.57	3.3E-04
1232	B-104	0.06	0.77	1.30	0.10	0.09	7.7E-06	0.06	0.71	1.19	0.09	0.08	7.1E-06
870	H-02	0.36	4.78	0.07	0.43	0.16	8.4E-05	0.33	4.37	0.06	0.40	0.14	7.7E-05
	Calculation Formula	= M * (1+S)	= N * (1+T)	= O * (1+U)	= P * (1+V)	= Q * (1+W)	= R * (1+X)	= M * (1+Y)	= N * (1+Z)	= O * (1+AA)	= P * (1+AB)	= Q * (1+AC)	= R * (1+AD)
	Heater Total	26.24	747.23	712.93	47.78	48.82	4.6E-03	24.01	683.62	652.23	43.71	44.67	4.2E-03
	No. 3 Boilerhouse	11.92	216.64	393.34	23.81	25.74	2.6E-03	10.90	198.20	359.85	21.78	23.55	2.4E-03
	Calculation Formula	= M * (1+S)	= N * (1+T)	= O * (1+U)	= P * (1+V)	= Q * (1+W)	= R * (1+X)	= M * (1+Y)	= N * (1+Z)	= O * (1+AA)	= P * (1+AB)	= Q * (1+AC)	= R * (1+AD)
	Heater/Boiler Total	38.16	963.87	1106.27	71.59	74.57	7.2E-03	34.91	881.81	1012.09	65.49	68.22	6.5E-03

PES Refinery
Heater Firing Rate Increase Plan Approval
Emission Estimates for Ancillary
Upstream/Downstream Unmodified
Heaters/Boiler

		AQ	AR	AS	AT	AU	AV
Unit	Heater	Emissions Increases from Plan Approval (TPY)					
		SOx	NOx	CO	PM	VOC	Lead
137	F-1	0.62	20.16	12.32	0.69	0.81	7.4E-05
137	F-2	0.11	4.46	2.63	0.14	0.17	1.6E-05
137	F-3	0.06	0.69	1.23	0.07	0.08	7.5E-06
210	13H-1	0.18	8.87	5.32	0.30	0.35	3.4E-05
1332	H-400**	0.13	1.45	4.78	0.43	0.31	2.9E-05
1332	H-401**	0.18	1.85	6.44	0.58	0.42	3.9E-05
1332	H-601	0.03	0.46	0.75	0.04	0.05	4.6E-06
1332	H-602	0.06	0.88	1.47	0.09	0.10	8.8E-06
1332	H-1	0.00	0.01	0.02	0.00	0.00	1.3E-07
1332	H-2	0.04	0.48	0.15	0.07	0.08	7.2E-06
1332	H-3	0.03	0.48	0.80	0.05	0.05	4.8E-06
860	2H2	0.04	0.89	1.39	0.08	0.09	8.9E-06
860	2H3	0.10	6.51	3.64	0.20	0.24	2.3E-05
860	2H4	0.05	1.20	1.87	0.10	0.12	1.2E-05
860	2H5	0.11	7.01	3.92	0.21	0.26	2.5E-05
860	2H7	0.04	0.91	1.43	0.08	0.09	9.1E-06
860	2H8	0.01	0.76	1.23	0.07	0.08	7.5E-06
864	PH1	0.04	0.89	1.48	0.08	0.10	7.1E-06
864	PH7	0.02	0.48	0.79	0.05	0.05	6.3E-06
864	PH11	0.04	0.85	1.41	0.08	0.09	8.0E-06
864	PH12	0.03	0.74	1.23	0.07	0.08	9.4E-06
859	1H1	0.06	0.64	0.92	0.14	0.17	8.6E-06
870	H-01	0.01	0.42	0.28	0.09	0.01	1.9E-06
433	H-1	0.19	2.07	5.08	0.31	0.33	3.0E-05
1232	B-104	0.01	0.07	0.11	0.01	0.01	6.6E-07
870	H-02	0.03	0.41	0.01	0.04	0.01	7.1E-06
	Calculation Formula	= (AE - M) - (AK - M)	= (AF - N) - (AL - N)	= (AG - O) - (AM - O)	= (AH - P) - (AN - P)	= (AI - Q) - (AO - Q)	= (AJ - R) - (AP - R)
	Heater Total	2.23	63.62	60.69	4.07	4.16	3.9E-04
	No. 3 Boilerhouse	1.01	18.44	33.49	2.03	2.19	2.2E-04
	Calculation Formula	= (AE - M) - (AK - M)	= (AF - N) - (AL - N)	= (AG - O) - (AM - O)	= (AH - P) - (AN - P)	= (AI - Q) - (AO - Q)	= (AJ - R) - (AP - R)
	Heater/Boiler Total	3.25	82.06	94.18	6.09	6.35	6.1E-04

PES Refinery
Heater Firing Rate Increase Plan Approval
Greenhouse Gas Emission Estimates for Ancillary Units

Crude Increase Basis

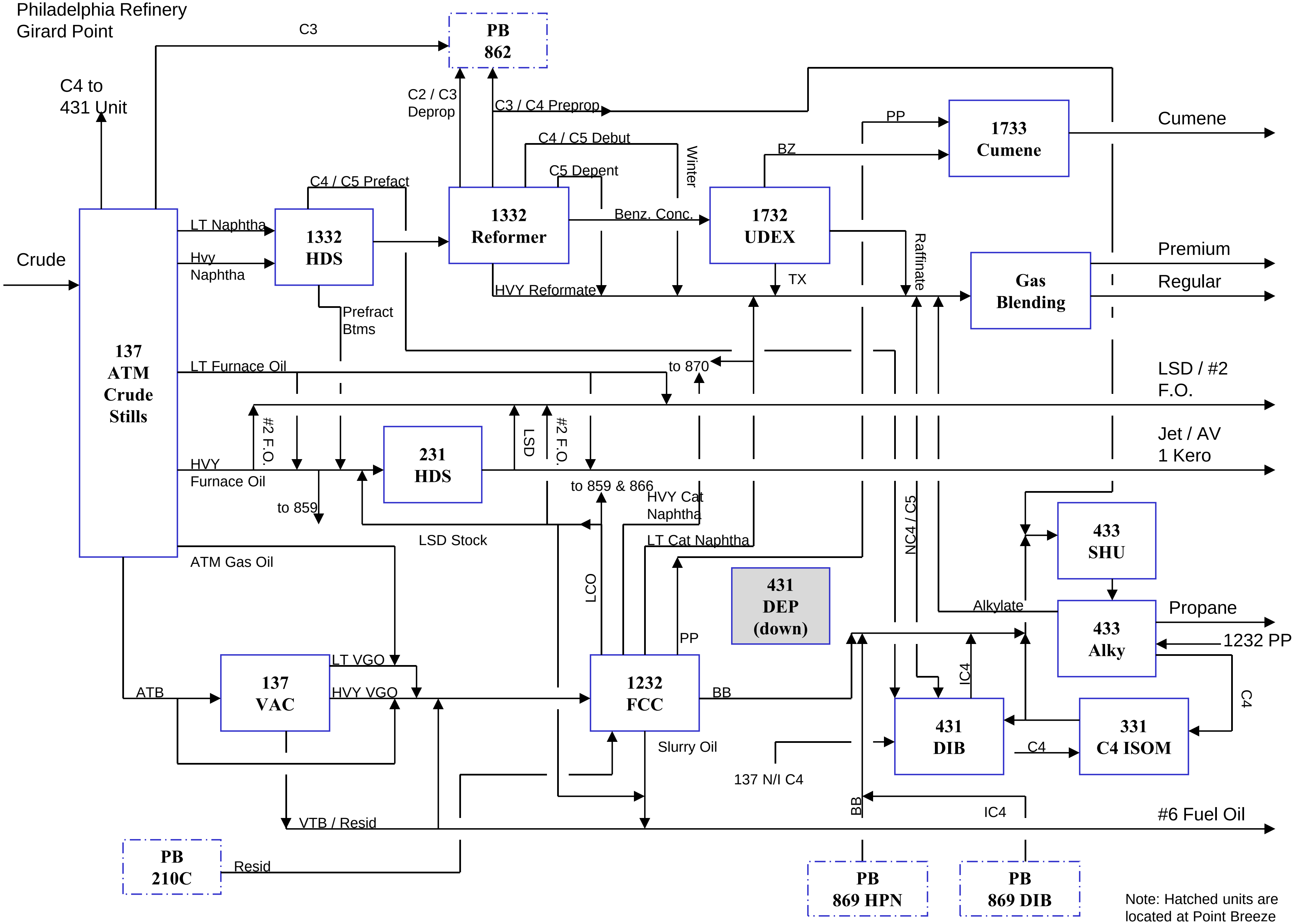
Crude Unit	24-month Actual Rate (MBPD)	Capable Rate - June 2010 (MBPD)	Capable increase from baseline (%)	Future Projected Actual Rate (MBPD)	Expected increase from this plan approval (%)
TOTAL	**284.4**	**316.5**	**111%**	**346.0**	**122%**

	A	B	C	D	E	F	G
Source	GHGe Report 2010 (mtons)	GHGe Report 2011 (mtons)	GHGe 24-month average (mtons)	GHGe Capable Increases from Baseline (%)	Expected increase from this plan approval (%)	Projected Future Actual Emissions (mton/year)*	Emissions Increases from Plan Approval (mton/year)
137 Unit	212,881	197,415	205,148	11%	22%	226,396	21,248
210 Unit Except H101 & H201	90,715	76,740	83,727	11%	22%	92,399	8,672
All Other (non-targeted) Heaters/Boiler	915,999	934,903	925,451	11%	22%	1,021,304	95,853
Unit 867 SRU	16,773	19,255	18,014	11%	22%	19,880	1,866
Girard Point MVRU	19,748	19,748	19,748	11%	22%	21,793	2,045
All LDAR	496	496	496	-	-	496	0
All Tanks	259	249	254	0.45%	0.87%	255	1.1
All Flares	45,068	17,138	31,103	-	-	31,103	0
Total	1,301,939	1,265,944	1,283,941			1,413,627	129,686
Calculation Formula			= Average(A,B)			= C * (1 + (E-D))	= F - C

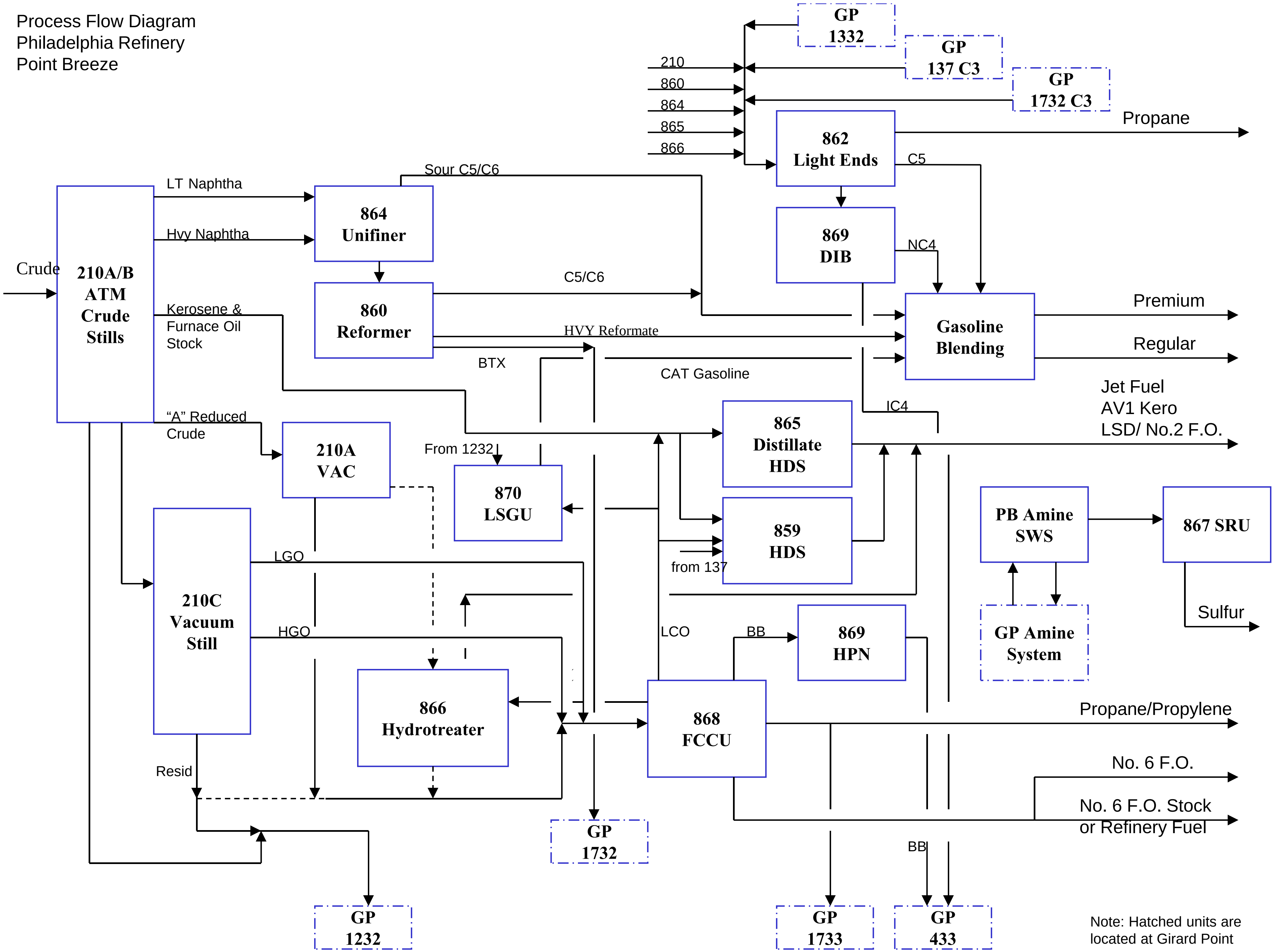
*** Only capable % increases that are greater than zero are subtracted from the expected % increases.**

Attachment E
Process Flow Diagrams/Site Location Map

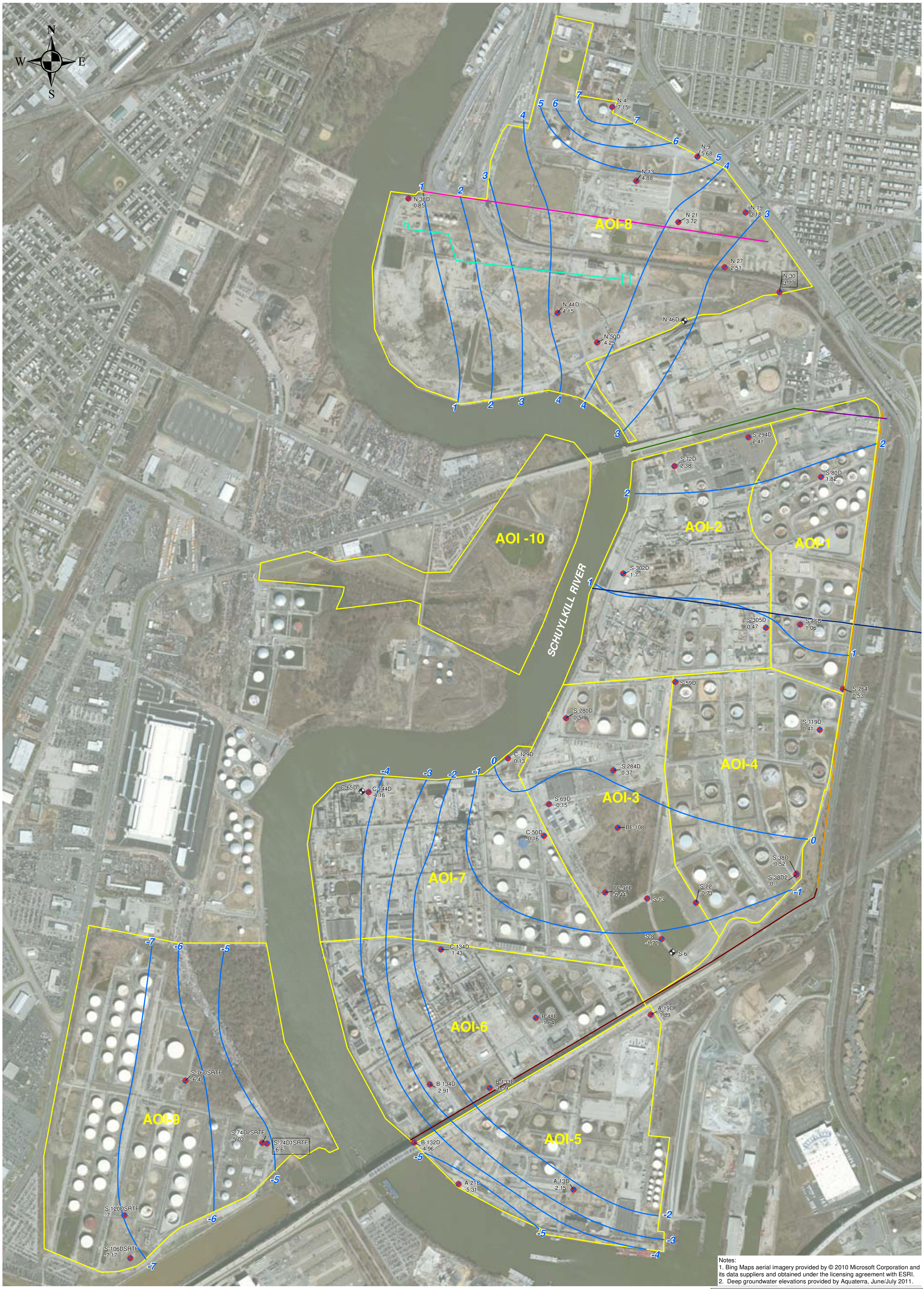
Process Flow Diagram
Philadelphia Refinery
Girard Point



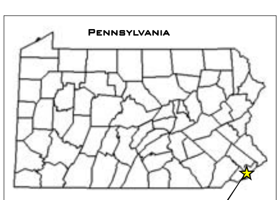
Process Flow Diagram
Philadelphia Refinery
Point Breeze



Note: Hatched units are located at Girard Point



Notes:
1. Bing Maps aerial imagery provided by © 2010 Microsoft Corporation and its data suppliers and obtained under the licensing agreement with ESRI.
2. Deep groundwater elevations provided by Aquaterra, June/July 2011.



Legend

- S-119D 0.41 — Deep Groundwater Monitoring Well and Groundwater Elevation
- N-46D — Damaged/Abandoned/Unable to Locate
- Deep Groundwater Contour
- Penrose Avenue Sewer
- Pollock Street Sewer
- Passyunk Avenue Sewer
- Shunk Street Sewer
- 26th Street Sewer
- Rambo Creek Sewer
- Jackson Street Sewer
- Area of Interest (AOI)
- N-30 3.77 — Wells Omitted From Contouring

Figure 7 - Deep (Lower Sand) Groundwater Elevation Contour Plan - June/July 2011
AOI-8 Site Characterizaton Report/
Remedial Investigation Report
Sunoco Philadelphia Refinery
Philadelphia, Pennsylvania

Sunoco, Inc. (R&M)
Philadelphia Refinery
3144 Passyunk Avenue
Philadelphia, PA.
19145

0 250 500 1,000 Feet

SCALE: 1" = 500'
DATE: November 7, 2011
DRN. BY: MH
CKD. BY: DW
JOB#: 2574601

Path: \\langan.com\data\DT\data6\2574601\ArcGIS\MapDocuments\AOI 8 SCR\SCR_RIR\Figure 7 - AOI-8 Deep GW Contours_1-30-12.mxd

Attachment F
CO Dispersion Modeling

Philadelphia Energy Solutions Refining and Marketing, LLC. (PES).

CO Dispersion Modeling for the Heater Firing Rate Increase

September 2013 Supplement

Environmental Resources Management
75 Valley Stream Parkway
Suite 200
Malvern, Pennsylvania 19355

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1.0 INTRODUCTION AND AIR QUALITY MODELING METHODOLOGY

On behalf of Philadelphia Energy Solutions (PES), Environmental Resources Management (ERM) has performed an air quality modeling analysis to assess compliance with the carbon monoxide (CO) Significant Impact Level (SIL) for the proposed plan approval at the Philadelphia Refinery.

ERM has performed the air quality modeling analysis in conformance with EPA's AERMOD implementation guidance. The key elements of the modeling analysis include:

- Use of the latest version of AERMOD (version 12345);
- Develop a comprehensive receptor grid designed to identify maximum plan approval concentration impacts;
- Use of surface meteorological data from Philadelphia International Airport (PHL) and upper air data from Sterling, VA for the period 2007-2011;
- Use of AERMET (version 12345) to process the meteorological data, with associated processors AERMINUTE (version 11325) and AERSURFACE (version 13016);
- Conduct air quality modeling to determine the magnitude and location of maximum ambient concentrations due to emissions of CO from the plan approval; and
- Compare maximum predicted impacts to the 1-hr and 8-hr CO SILs.

2.0 PLAN APPROVAL EMISSIONS AND SOURCE CHARACTERIZATION

A facility location map is presented in Appendix A of this report. Table 2-1 presents the emissions and modeled source parameters associated with all plan approval related sources. The CO emissions shown in Table 2-1 are the total plan approval emission increases from the target heaters and the upstream/downstream ancillary units. To be conservative, only the contemporaneous CO emissions increases are included in the analysis. For this air quality modeling analysis, the emissions decreases that occurred contemporaneously at Marcus Hook have not been included. Appendix B of this report presents the locations of all modeled sources.

Table 2-1 – Emission Rates and Modeled Source Parameters

Height m	Diameter m	Exit Velocity m/s	Temp. ° K	UTME m	UTM N m	Base Elevation m	CO (tpy)	CO (g/s)	AERMOD ID	Source Name
60.96	3.96	4.61	450.2	481824	4417696.91	2.30	12.32	0.354	1	Unit 137 F-1 Heater
22.86	1.05	19.85	561.2	482193	4416912.34	2.38	15.88	0.457	2	Unit 231-B101 Heater
60.96	3.96	1.91	450.2	481807	4417719.35	2.46	2.63	0.076	3	Unit 137 F-2 Heater
23.01	1.37	4.63	505.2	481807	4417719.57	2.47	1.23	0.035	4	Unit 137 F-3 Heater
30.48	2.29	6.05	527.2	482178	4417034.35	2.47	4.78	0.138	5	Unit 1332 H-400 Heater
30.48	2.29	7.58	416.2	482235.3	4416966.19	2.69	6.92	0.199	6	Unit 1332 H-401 Heater
25.60	1.37	7.46	661.2	482219	4416978.75	2.47	0.75	0.022	7	Unit 1332 H-601 Heater
26.82	1.45	5.73	755.2	482229	4416983.31	2.40	1.47	0.042	8	Unit 1332 H-602 Heater
27.43	1.98	3.60	519.2	482204.87	4417002.24	2.41	0.02	0.001	9	Unit 1332 H-1 Heater
26.82	1.37	10.40	782.2	482208.83	4416994.20	2.38	0.15	0.004	10	Unit 1332 H-2 Heater
27.43	1.98	2.46	637.2	482214.67	4416986.24	2.44	0.80	0.023	11	Unit 1332 H-3 Heater
41.45	2.90	5.65	505.2	482104.31	4417244.63	2.5	5.18	0.149	12	Unit 433 H-1 Heater
35.05	2.44	5.85	755.2	482215.86	4417502.42	2.6	0.11	0.003	13	Unit 1232 B-104 Heater
60.96	5.79	12.07	489.2	481877.7	4416989.67	2.36	115.89	3.334	14	No. 3 Boilerhouse
16.76	3.05	4.52	1110.9	482653.65	4416170.07	1.66	0.22	0.006	15	GP BARGE LOADING (MVRU)
76.64	6.46	20.00	1273	481621.96	4416503.93	2.61	0.51	0.015	16	Butane Truck Unloading at SRTF
42.68	1.83	5.82	589.2	483138.63	4418599.73	7.31	19.68	0.566	18	Unit 865-11H1 Heater
55.17	1.88	3.05	555.4	483153.74	4418600.53	7.28	6.31	0.182	19	Unit 865-11H2 Heater
41.61	2.25	9.04	611.2	482862.71	4418515.03	6.63	9.99	0.287	20	Unit 210-H101 Heater
60.82	2.90	8.40	519.2	482881.52	4418507.91	6.74	23.24	0.669	21	Unit 210-H201 Heater
38.10	1.52	3.67	460.9	483180.68	4418601.49	7.35	12.02	0.346	22	Unit 866-12H1 Heater
35.95	1.31	6.64	533.2	483241.27	4418379.69	6.41	3.44	0.099	23	Unit 868-8H101 Heater
66.40	3.23	6.13	627.2	482935.72	4418489.91	7.06	5.32	0.153	24	Unit 210 13H-1 Heater
35.64	1.91	16.16	623.2	482900.35	4418267.46	5.1	1.39	0.040	25	Unit 860 2H2 Heater
33.53	2.05	22.57	623.2	482895.26	4418244.61	5.22	3.64	0.105	26	Unit 860 2H3 Heater
35.64	1.91	16.16	623.2	482903.55	4418244.14	5.12	1.87	0.054	27	Unit 860 2H4 Heater
33.53	2.05	22.57	623.2	482921.44	4418256.98	5.11	3.92	0.113	28	Unit 860 2H5 Heater
33.53	1.37	8.50	633.2	482918.85	4418286.84	5.05	1.43	0.041	29	Unit 860 2H7 Heater
33.53	1.37	7.66	626.2	482922.88	4418292.60	5.17	1.23	0.035	30	Unit 860 2H8 Heater
39.09	1.49	10.29	680.4	483162.38	4418496.84	7.26	1.48	0.042	31	Unit 864 PH1 Heater
33.53	1.37	6.56	610.2	483171.37	4418500.49	7.27	0.79	0.023	32	Unit 864 PH7 Heater
33.53	1.49	9.21	686.2	483182.65	4418499.69	7.24	1.41	0.041	33	Unit 864 PH11 Heater
36.58	1.63	9.68	655.2	483193.84	4418501.33	7.28	1.23	0.035	34	Unit 864 PH12 Heater
44.81	1.93	6.80	703.7	482731.53	4418221.67	5.02	88.59	2.548	35	Unit 859 1H1 Heater
43.55	1.80	7.58	701.2	483157.79	4418158.45	5.99	0.28	0.008	36	Unit 870 H-01 Heater
37.49	1.14	10.32	873.2	483165.8	4418146.56	5.99	0.01	0.000	37	Unit 870 H-02 Heater
69.80	1.01	29.22	802.2	482696.29	4418207.43	5.07	18.71	0.538	38	Sulfur Recovery Unit

Release Height m	Sigma Y m	Sigma Z m	UTME m	UTM N m	Base Elevation m	CO (tpy)	CO (g/s)	AERMOD ID	Source Name
3.048	11.39	2.84	483059.95	4417975.87	4.39	0.45	0.013	39	Tank P-590 (PB 843) Reactivation

2.1 BUILDING WAKE EFFECTS

The EPA's Building Profile Input Program (BPIP), Version 04274, were used to calculate downwash effects for the modeled emission sources. Buildings were identified that could potentially affect the modeled sources. A figure showing the locations of sources and buildings is presented in Appendix C.

3.0 MODELING METHODOLOGY

3.1 MODEL SELECTION AND APPLICATION

The latest version of EPA's AERMOD model (version 12345) was used for predicting ambient impacts for carbon monoxide (CO). Regulatory default options were used in the analysis. The highest predicted impacts (H1H) are reported for the analyses presented in this report.

3.2 AMBIENT AIR QUALITY STANDARDS

Ambient air quality standards that were addressed are different for criteria pollutants (for which NAAQS have been established) and non-criteria pollutants for which ESLs have been established. Table 3-1 presents a summary of the air quality standards that were addressed for PM_{10}, $PM_{2.5}$, and CO (PSD pollutants), and for SO_2 (subject to a State NAAQS analysis). The SILs are presented, along with the significant monitoring concentrations (SMCs), PSD increments, and NAAQS. If plan approval impacts are shown to be less than the SILs and SMCs, then no further analysis is required. If the SILs are exceeded, additional analysis would be necessary including the development of a background source inventory and background measured concentrations. Section 4 of this report contains the results of the air quality modeling analyses for all pollutants. The results presented in Section 4 show that the proposed plan approval is less than the applicable SILs for CO.

Table 3-1 Ambient Standards for Carbon Monoxide (CO)

Parameter	Averaging Period	SIL	SMC	Increment	NAAQS
CO	1 Hour	2,000	-	-	40,000
	8 Hour	500	575	-	10,000

NOTE: All concentrations are shown in micrograms/cubic meter

3.3 GEOGRAPHIC SETTING AND AREA MAPS

3.3.1 Land Use Characteristics

A facility location map is presented in Appendix A. The map was created using aerial imagery. In order to determine the appropriateness of

AERMOD's urban source option, the land use classification within a 3-km radius of the facility was determined using USGS 1992 LULC data. Land use within three kilometers of the facility was determined to be approximately 72% urban land use classification. Therefore, the urban option available in AERMOD will be used. The population of Philadelphia County, estimated for 2011 at 1,536,471 individuals by the US Census, will be used in AERMOD as input in the nighttime urban boundary layer algorithm.

3.3.2 Terrain

Terrain elevations and hill scales were determined for use in this analysis. The latest version of EPA's AERMAP program (version 11103) was used to determine the ground elevation and hill scale for each receptor, based on data obtained from the USGS National Elevation Database (NED).

3.4 RECEPTOR GRID

For this modeling analysis, a total of four separate receptor grids were combined to create an overall grid pattern:

1. Receptors at 25-m spacing located along the property fence-line;
2. Receptors spaced at 75-m out to 500 m from the fence-line;
3. Receptors at 100-m spacing located from 100 m from the approximate center of the facility to a distance of 2 km;
4. Receptors at 500-m spacing located from 2 km from the approximate center of the facility to a distance of 5 km; and
5. Receptors at 1-km spacing located from 5 km from the approximate center of the facility to a distance of 15 km.

Appendix D presents a figure of the inner portion of the receptor grid. As noted previously, AERMAP was used to define ground elevations and hill scales for each receptor.

3.5 METEOROLOGY

The met data approved for use in this dispersion modeling analyses is based on surface observations from Philadelphia International Airport (PHL), and upper air measurements from Sterling, VA. The PHL AutomaTIC Surface observation Station (ASOS) is located approximately 4 km to the southwest of the central area of the PES Refinery.

Meteorological data from 2007 through 2011 were used, which represents the most recent available and complete five year continuous data period.

The surface and upper air meteorological data were processed using AERMET. The micrometeorological variables necessary for AERMET were generated by the AERSURFACE land use processing program. AERSURFACE was executed using the location of the PHL ASOS station available from the National Climatic Data Center (NCDC). The output from AERSURFACE was then merged with the meteorological data from PHL and Sterling, VA to create the data ready for input into AERMOD. The following assumptions and settings were used in the execution of AERMET and AERSURFACE:

- 2007-2011 surface data, ISHD data format
- Upper air data from Sterling, VA, FSL format
- Most recent version of AERMET, version 12345
- Location of PHL (from NCDC): **39.885 N, 75.236 W**
- Elevation of PHL (from ISHD data file): **3.05 m**
- Anemometer Height (standard ASOS station height): **7.92 m**
- Location of Sterling Upper Air Station (from FSL): **3 38.98 N, 77.47 W**
- 1-minute ASOS winds from PHL processed with AERMINUTE
  - Ice-free wind sensor installation date for PHL: **7/30/2009**
- Surface data derived from AERSURFACE
  - 1-km radius for surface roughness
  - 10x10km area for Bowen ratio and albedo
  - 12 sector surface roughness
  - AERSURFACE Options:
    - Generated by AERSURFACE, dated 13016
    - Center Latitude (decimal degrees): **39.884913**
    - Center Longitude (decimal degrees): **- 75.235735**
    - Datum: NAD83
    - Study radius (km) for surface roughness: **1.0**
    - Airport? **Yes**
    - Continuous snow cover? **No**
    - Surface moisture? **Varies, see below**
    - Arid region? **No**
    - Month/Season assignments? **Default**

    - Late autumn after frost and harvest, or winter with no snow: **12 1 2**
    - Winter with continuous snow on the ground: **0**
    - Transitional spring (partial green coverage, short annuals): **3 4 5**
    - Midsummer with lush vegetation: **6 7 8**
    - Autumn with unharvested cropland: **9 10 11**

- Surface moisture was determined year by year following the methodology in the AERMOD implementation guide, using rainfall from PHL for the period of record for 1982-2011. The implementation guidance states that years with rainfall above the 70th percentile should use the WET option in AERSURFACE, years with less than the 30th percentile should use the DRY option, and the middle 30th percentile to 70th percentile should use the AVERAGE option. Rainfall data were obtained for PHL from NCDC for the 30 year period. Appendix E of this report contains a summary of these data, as well as the calculated percentile of each year's rainfall with respect to the 30 year period.

- No substitution for missing data.

4.0 MODEL RESULTS PRESENTATION

The result of the CO SIL modeling analysis is shown in Table 4-1. The highest 1-hr and 8-hr modeled concentrations over the five year model period are well below the SILs. As a result, the plan approval increase in carbon monoxide (CO) will not cause or contribute to any exceedance of the CO NAAQS, and no further air quality modeling analyses are required.

Table 4-1 SIL Analysis Results – Carbon Monoxide (CO)

Maximum Modeled Concentrations

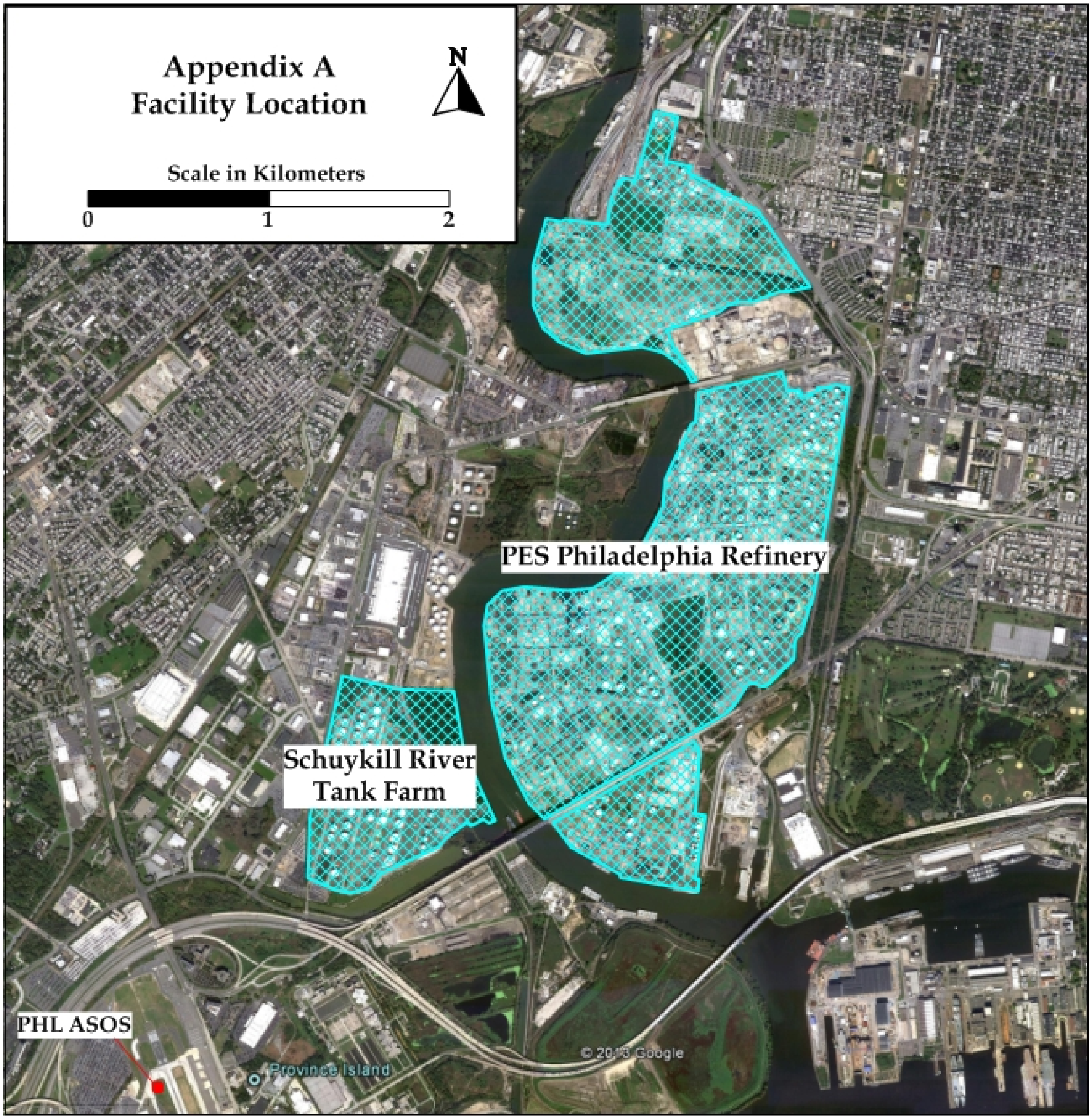
Pollutant	Averaging Period	Maximum Concentration	Significant Impact Level	Impact Significant?	2007	2008	2009	2010	2011
CO	8-hr	12.81	500	No	11.97	12.14	12.81	11.25	11.55
	1-hr	16.22	2000	No	15.57	15.31	16.22	15.78	15.87

Location of Maximum Modeled Concentrations

Pollutant	Averaging Period	Maximum Concentration	Year	UTME (m)	UTMN (m)	Elevation (m)	Flagpole (m)
CO	8-hr	12.81	2009	482504	4417967	5.9	0
	1-hr	16.22	2009	482540	4418033	6.4	0

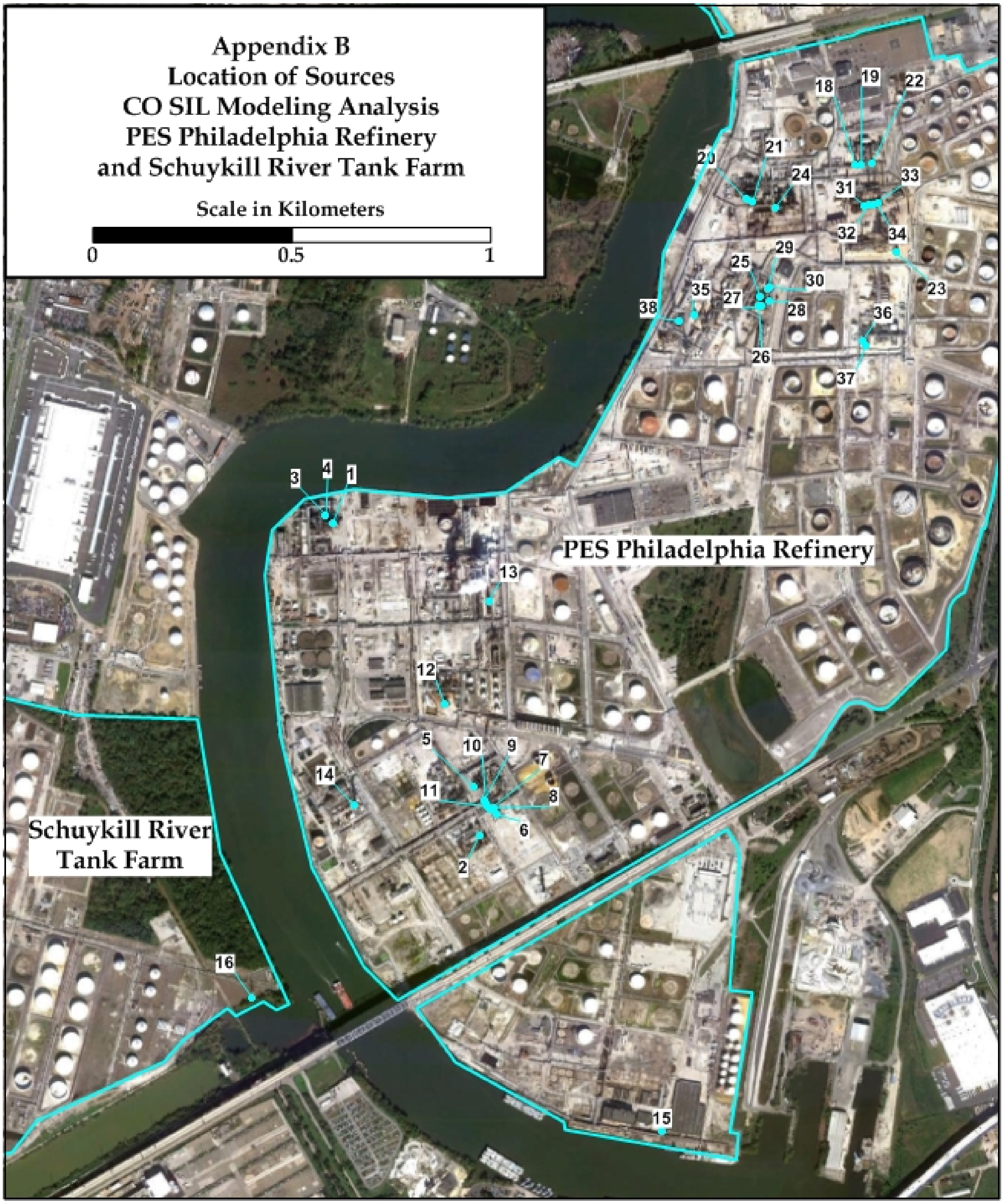
Notes:
1. All concentrations are in $\mu g/m^3$

Appendix A
Facility Location



Appendix A
Facility Location
N
Scale in Kilometers
0
1
2
PES Philadelphia Refinery
Schuylkill River
Tank Farm
PHL ASOS
Province Island
© 2013 Google

Appendix B
Source Location


Appendix B
Location of Sources
CO SIL Modeling Analysis
PES Philadelphia Refinery
and Schuylkill River Tank Farm
Scale in Kilometers
0
0.5
1
PES Philadelphia Refinery
Schuylkill River
Tank Farm
1
2
3
4
5
6
7
8
9
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15
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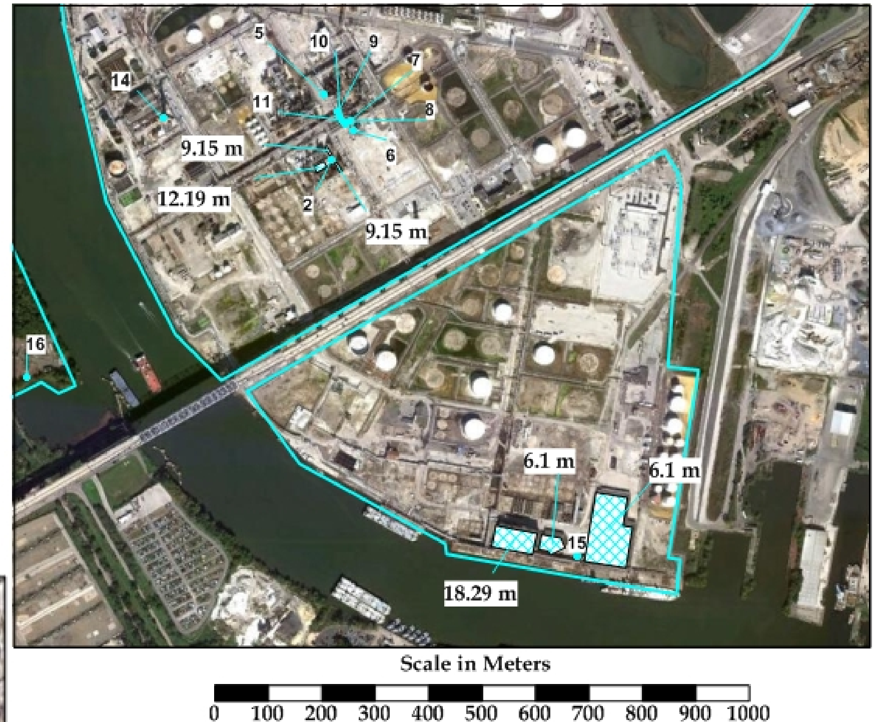
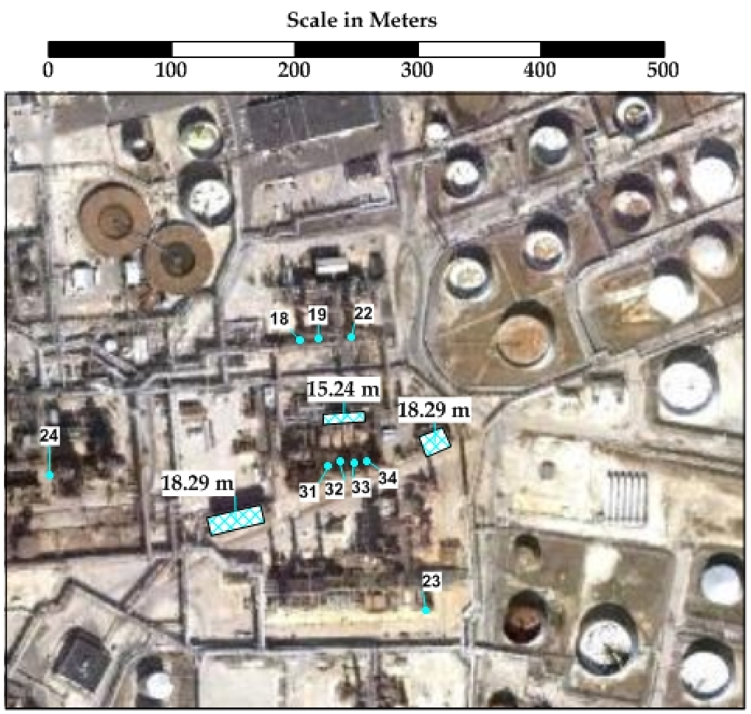
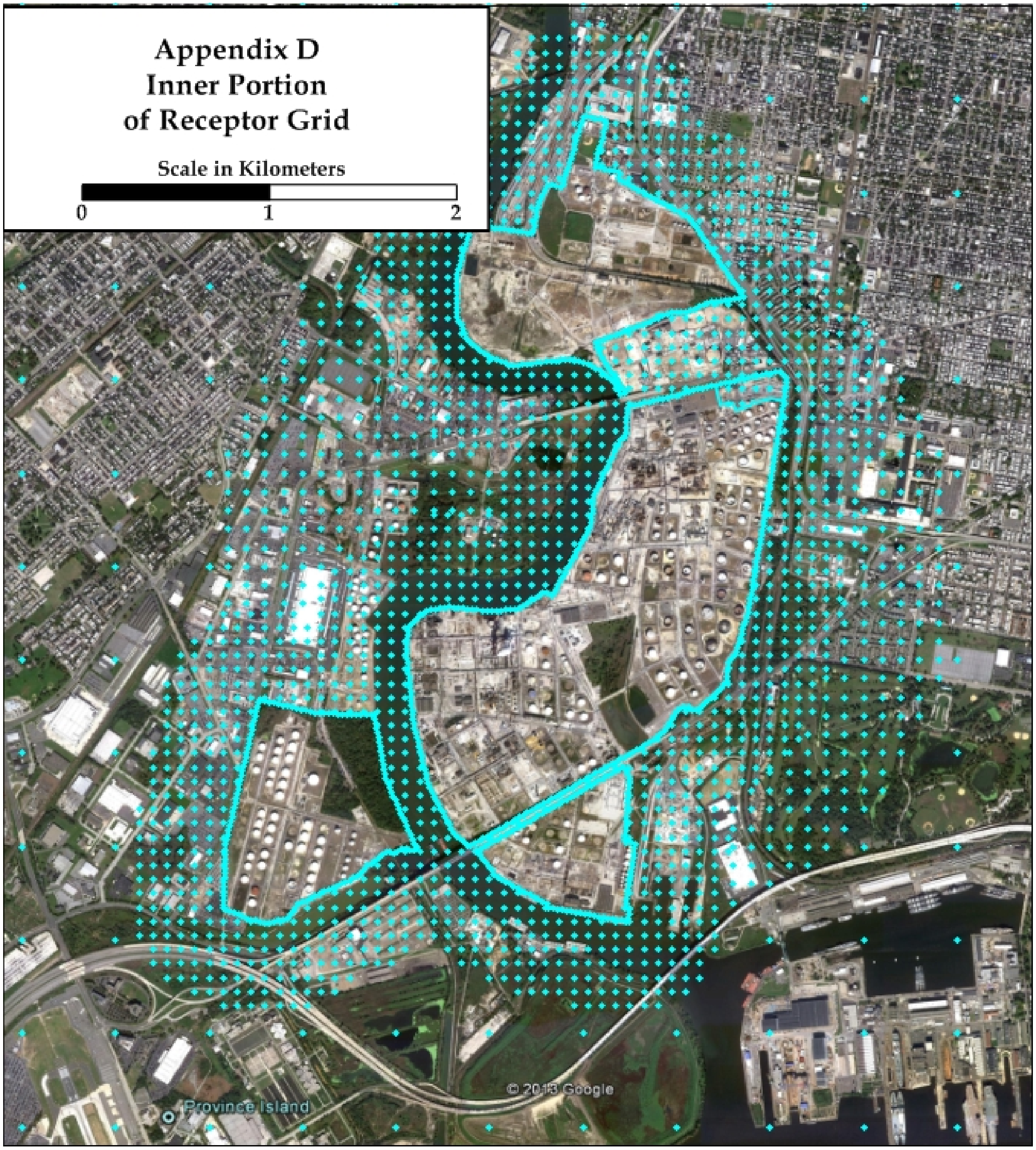
Appendix C
Building Downwash Structures

Appendix C
Location of Sources and Downwash Structures
CO SIL Modeling Analysis
PES Philadelphia Refinery





Appendix D
Receptor Grid


Appendix D
Inner Portion
of Receptor Grid
Scale in Kilometers
0
1
2
© 2013 Google
Province Island

Appendix E
30 Year Annual Rainfall – Philadelphia International Airport (PHL)

Appendix E

PHL - Annual Rainfall

Year	Rainfall (in.)	Percentile of 30 Year Record		30th Percentile (in.)	70th percentile (in.)			
1982	40.43	0.448		37.75	45.84			Dry
1983	54.66	0.931						Average
1984	43.66	0.586						Wet
1985	35.2	0.206						
1986	40.42	0.413						
1987	33.4	0.172						
1988	38.41	0.31						
1989	48.66	0.827						
1990	35.79	0.241						
1991	36.22	0.275						
1992	30.41	0						
1993	42.18	0.517						
1994	44.92	0.689						
1995	31.53	0.068						
1996	56.45	0.965						
1997	32.52	0.137						
1998	31.65	0.103						
1999	48.49	0.793						
2000	44.57	0.655						
2001	31.01	0.034						
2002	39.34	0.344						
2003	47.98	0.724						
2004	49.19	0.862						
2005	42.22	0.551						
2006	48.2	0.758						
2007	42.13	0.482						
2008	40.33	0.379						
2009	52.5	0.896						
2010	44.46	0.62						
2011	64.32	1						

Attachment G
RBLC and BAAQMD BACT
Search Results

Summary

NOx

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	DATE DETERMINATION LAST UPDATED	FACILITY DESCRIPTION	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL
PA-0252	SUNOCO, INC. (R&M)	SUNOCO, INC. (R&M)	PA	8/18/2008	PETROLEUM REFINERY	433 H-1 HEATER	11.3	REFINERY FUEL GAS
WA-0324	FERNDALE REFINERY	CONOCOPHILLIPS REFINING COMPANY	WA	1/26/2006	PETROLEUM REFINERY	CGD FEED HEATER (MODEL ID SRC19)	11.31	NATURAL GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	A&B CRUDE HEATERS (1-08 & 2-08); COKER CHARGE HEATER (15-08)	11.39	REFINERY FUEL GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	PLATFORMER HEATER CELLS NO. 1-3 (7A-08, 7B-08, 7C-08); HCU FRACTIONATOR HEATER (13-08)	11.39	REFINERY FUEL GAS
LA-0213	ST. CHARLES REFINERY	VALERO REFINING - NEW ORLEANS, LLC	LA	3/5/2010	PETROLEUM REFINERY	HEATER F-72-703 (7-81)	11.39	REFINERY FUEL GAS
NM-0050	ARTESIA REFINERY	NAVAJO REFINING COMPANY LLC	NM	8/1/2008	PETROLEUM REFINERY	ROSE 2 HOT OIL HEATER	12.3	REFINERY FUEL GAS
OK-0126	SUNOCO INC TULSA REFINERY	SUNOCO INC	OK	4/20/2009	PETROLEUM REFINERY	PROCESS HEATER	12.31	REFINERY FUEL GAS
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	8/2/2010	PETROLEUM REFINERY	CRUDE UNIT VACUUM HEATER 21-H-2	12.39	REFINERY FUEL GAS
*WY-0071	SINCLAIR REFINERY	SINCLAIR WYOMING REFINING COMPANY	WY	10/15/2012	PETROLEUM REFINERY	BSI Heater	13.3	Refinery Fuel Gas
WA-0301	BP CHERRY POINT REFINERY	BRITISH PETROLEUM	WA	5/16/2006	PETROLEUM REFINERY	PROCESS HEATER, IHT	13.31	NATURAL GAS
PA-0256	SUNOCO, INC. (R&M)	SUNOCO, INC. (R&M)	PA	4/24/2008	PETROLEUM REFINERY	1H-5 HEATER	13.39	REFINERY FUEL GAS

PM

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	DATE DETERMINATION LAST UPDATED	FACILITY DESCRIPTION	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL
MT-0030	BILLINGS REFINERY	CONOCOPHILLIPS COMPANY	MT	3/9/2009	PETROLEUM REFINERY	NO. 1 H2 HEATER	11.3	REFINERY FUEL GAS/ PSA GAS
NM-0050	ARTESIA REFINERY	NAVAJO REFINING COMPANY LLC	NM	8/1/2008	PETROLEUM REFINERY	STEAM METHANE REFORMER HEATER	11.3	NATURAL GAS AND REFORMER OFF-GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	PLATFORMER HEATER CELLS NO. 1-3 (7A-08, 7B-08, 7C-08); HCU FRACTIONATOR HEATER (13-08)	11.39	REFINERY FUEL GAS
LA-0213	ST. CHARLES REFINERY	VALERO REFINING - NEW ORLEANS, LLC	LA	3/5/2010	PETROLEUM REFINERY	CPF HEATER H-39-03; H-39-02 (94-28; 94-30)	13.39	REFINERY FUEL GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	THERMAL DRYING UNIT HEATEC HEATER (124-1-91)	13.39	REFINERY FUEL GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	A&B VACUUM TOWER HEATERS (3-08; 4-08)	12.39	REFINERY FUEL GAS
LA-0213	ST. CHARLES REFINERY	VALERO REFINING - NEW ORLEANS, LLC	LA	3/5/2010	PETROLEUM REFINERY	HEATERS (2008-1 - 2008-9)	12.39	PROCESS FUEL GAS

CO

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	DATE DETERMINATION LAST UPDATED	FACILITY DESCRIPTION	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL
NM-0050	ARTESIA REFINERY	NAVAJO REFINING COMPANY LLC	NM	8/1/2008	PETROLEUM REFINERY	STEAM METHANE REFORMER HEATER	11.3	NATURAL GAS AND REFORMER OFF-GAS
LA-0213	ST. CHARLES REFINERY	VALERO REFINING - NEW ORLEANS, LLC	LA	3/5/2010	PETROLEUM REFINERY	HEATER F-72-703 (7-81)	11.39	REFINERY FUEL GAS
MS-0086	CHEVRON PRODUCTS COMPANY, PASCAGOUL	CHEVRON PRODUCTS COMPANY	MS	3/4/2010	PETROLEUM REFINERY	FOUR PLATFORMER FEED/INTERSTAGE HEATER WITH A COMMON STACK	11.39	REFINERY FUEL GAS
NM-0050	ARTESIA REFINERY	NAVAJO REFINING COMPANY LLC	NM	8/1/2008	PETROLEUM REFINERY	ROSE 2 HOT OIL HEATER	12.3	REFINERY FUEL GAS
LA-0238	ALLIANCE REFINERY	CONOCOPHILLIPS COMPANY	LA	5/18/2012	PETROLEUM REFINERY	FCCU FEED HEATER	12.31	REFINERY GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	A B VACUUM TOWER HEATERS (3-08; 4-08)	12.39	REFINERY FUEL GAS
*WY-0071	SINCLAIR REFINERY	SINCLAIR WYOMING REFINING COMPANY	WY	10/15/2012	PETROLEUM REFINERY	581 Crude Heater	12.39	Refinery Fuel Gas
*WY-0071	SINCLAIR REFINERY	SINCLAIR WYOMING REFINING COMPANY	WY	10/15/2012	PETROLEUM REFINERY	BSI Heater	13.3	Refinery Fuel Gas
NM-0050	ARTESIA REFINERY	NAVAJO REFINING COMPANY LLC	NM	8/1/2008	PETROLEUM REFINERY	SULFUR RECOVERY HOT OIL HEATER	13.3	REFINERY FUEL GAS
WA-0301	BP CHERRY POINT REFINERY	BRITISH PETROLEUM	WA	5/16/2006	PETROLEUM REFINERY	PROCESS HEATER, IHT	13.31	NATURAL GAS
*WY-0071	SINCLAIR REFINERY	SINCLAIR WYOMING REFINING COMPANY	WY	10/15/2012	PETROLEUM REFINERY	Naphtha Splitter Heater	13.39	Refinery Fuel Gas
LA-0213	ST. CHARLES REFINERY	VALERO REFINING - NEW ORLEANS, LLC	LA	3/5/2010	PETROLEUM REFINERY	DHT HEATERS (4-81, 5-81)	13.39	REFINERY FUEL GAS

VOC

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	DATE DETERMINATION LAST UPDATED	FACILITY DESCRIPTION	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL
NM-0050	ARTESIA REFINERY	NAVAJO REFINING COMPANY LLC	NM	8/1/2008	PETROLEUM REFINERY	STEAM METHANE REFORMER HEATER	11.3	NATURAL GAS AND REFORMER OFF-GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	PLATFORMER HEATER CELLS NO. 1-3 (7A-08, 7B-08, & 7C-08) & HCU FRACTIONATOR HEATER (13-08)	11.39	REFINERY FUEL GAS
NM-0050	ARTESIA REFINERY	NAVAJO REFINING COMPANY LLC	NM	8/1/2008	PETROLEUM REFINERY	ROSE 2 HOT OIL HEATER	12.3	REFINERY FUEL GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	A & B VACUUM TOWER HEATERS (3-08 & 4-08)	12.39	REFINERY FUEL GAS
LA-0211	GARYVILLE REFINERY	MARATHON PETROLEUM CO LLC	LA	7/16/2008	PETROLEUM REFINERY	THERMAL DRYING UNIT HEATEC HEATER (124-1-91)	13.39	REFINERY FUEL GAS

Summary

NOx

RBLCID	FACILITY NAME	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS
PA-0252	SUNOCO, INC. (R&M)	260	MMBTU/H	Nitrogen Oxides (NOx)		0.035	LB/MMBTU	HOURLY	BACT-PSD
WA-0324	FERNDALE REFINERY			Nitrogen Oxides (NOx)	ULTRALOW LOW NOX BURNER	17	PPMDV	7% O2 OVER A 1-HOUR AVERAGING	BACT-PSD
LA-0211	GARYVILLE REFINERY	0	0	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS (ULNB) AND SELECTIVE CATALYTIC REDUCTION (SCR VOLUNTARY)	0.0125	LB/MMBTU	ANNUAL AV	BACT-PSD
LA-0211	GARYVILLE REFINERY	0	0	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS (ULNB) WITHOUT AIR PREHEAT	0.03	LB/MMBTU	ANNUAL AVERAGE	BACT-PSD
LA-0213	ST. CHARLES REFINERY	633	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS	0.08	LB/MMBTU	THREE ONE HOUR AVERAGE	BACT-PSD
NM-0050	ARTESIA REFINERY	120	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS	0.03	LB/MMBTU	3-HOUR ROLLING AVERAGE @ 3% O2	BACT-PSD
OK-0126	SUNOCO INC TULSA REFINERY	44	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA LOW-NOX BURNERS	0.03	LB/MMBTU	3 HOUR AVERAGE	BACT-PSD
DE-0020	VALERO DELAWARE CITY REFINERY	240	MMBTU/H	Nitrogen Oxides (NOx)	SCR	0.04	LB/MMBTU	3-HR ROLLING AV	RACT
*WY-0071	SINCLAIR REFINERY	50	MMBtu/hr	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.025	LB/MMBTU	3-HR AVERAGE	BACT-PSD
WA-0301	BP CHERRY POINT REFINERY	13	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS	0.1	LB/MMBTU	7% O2, 24 hr ave	BACT-PSD
PA-0256	SUNOCO, INC. (R&M)	98	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS	0.02	LBS/MMBTU	THREE 1-HOUR TESTS	LAER

PM

RBLCID	FACILITY NAME	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS
MT-0030	BILLINGS REFINERY	266	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	GOOD COMBUSTION PRACTICES/USE OF CLEAN BURNING FUELS	0.0075	LB/MMBTU	PER ROLLING 12-MONTH TIME PERIOD	BACT-PSD
NM-0050	ARTESIA REFINERY	337	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	GASEOUS FUEL COMBUSTION ONLY	0.0075	LB/MMBTU	HOURLY	BACT-PSD
LA-0211	GARYVILLE REFINERY			Particulate matter, filterable < 10 µ (FPM10)	PROPER DESIGN, OPERATION, AND GOOD ENGINEERING PRACTICES	0.0075	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD
LA-0213	ST. CHARLES REFINERY			Particulate matter, total < 10 µ (TPM10)	PROPER EQUIPMENT DESIGN AND OPERATION, GOOD COMBUSTION PRACTICES, AND USE OF GASEOUS FUELS	0.0074	LB/MMBTU	ANNUAL AVERAGE	BACT-PSD
LA-0211	GARYVILLE REFINERY	9.6	MM BTU/H	Particulate matter, filterable < 10 µ (FPM10)		0.05	MAX LB/H		BACT-PSD
LA-0211	GARYVILLE REFINERY	155.2	MMBTU/H EA.	Particulate matter, filterable < 10 µ (FPM10)	PROPER DESIGN, OPERATION, AND GOOD ENGINEERING PRACTICES	0.0075	LB/MMBTU	3 HR AV	BACT-PSD
LA-0213	ST. CHARLES REFINERY			Particulate matter, total < 10 µ (TPM10)	COMPLY WITH 40 CFR 60 SUBPARTS NNN AND RRR	0		SEE NOTE	BACT-PSD

CO

RBLCID	FACILITY NAME	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS
NM-0050	ARTESIA REFINERY	337	MMBTU/H	Carbon Monoxide	GASEOUS FUEL COMBUSTION ONLY	0.06	LB/MMBTU	3-HOUR ROLLING AVERAGE	BACT-PSD
LA-0213	ST. CHARLES REFINERY	633	MMBTU/H	Carbon Monoxide	PROPER DESIGN AND OPERATION, GOOD COMBUSTION PRACTICES	0.08	LB/MMBTU	THREE ONE HOUR TEST AVERAGE	BACT-PSD
MS-0086	CHEVRON PRODUCTS COMPANY, PASCAGOUL	850	MMBTU/H	Carbon Monoxide		132.6	LB/H	3-HR AVERAGE	BACT-PSD
NM-0050	ARTESIA REFINERY	120	MMBTU/H	Carbon Monoxide	GASEOUS FUEL COMBUSTION ONLY	0.06	LB/MMBTU	3-HOUR ROLLING AVERAGE @ 3% O2	BACT-PSD
LA-0238	ALLIANCE REFINERY	181.7	MMBTU/H	Carbon Monoxide	EQUIPPED WITH VORTOMETRIC HIGH INTENSITY COMBUSTION UNIT	0.55	LB/H	HOURLY MAXIMUM	BACT-PSD
LA-0211	GARYVILLE REFINERY	155.2	MMBTU/H EA.	Carbon Monoxide	PROPER DESIGN, OPERATION, AND GOOD ENGINEERING PRACTICES	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD
*WY-0071	SINCLAIR REFINERY	233	MMBtu/hr	Carbon Monoxide	Good Combustion Practices	0.04	LB/MMBTU	3-HR AVERAGE	BACT-PSD
*WY-0071	SINCLAIR REFINERY	50	MMBtu/hr	Carbon Monoxide	Ultra Low NOx burners/good combustion practices	0.04	LB/MMBTU	3-HR AVERAGE	BACT-PSD
NM-0050	ARTESIA REFINERY	9.6	MMBTU	Carbon Monoxide	GOOD COMBUSTION PRACTICES	0		SEE NOTE	BACT-PSD
WA-0301	BP CHERRY POINT REFINERY	13	MMBTU/H	Carbon Monoxide	GOOD COMBUSTION PRACTICES	70	PPM	7% O2, 24 hr ave	BACT-PSD
*WY-0071	SINCLAIR REFINERY	46.3	MMBtu/hr	Carbon Monoxide	Good Combustion Practices	0.04	LB/MMBTU	3-HR AVERAGE	BACT-PSD
LA-0213	ST. CHARLES REFINERY	70	MMBTU/H EA	Carbon Monoxide	PROPER DESIGN AND OPERATION, GOOD COMBUSTION PRACTICES	0.08	LB/MMBTU	THREE ONE HOUR TEST AVERAGE	BACT-PSD

VOC

RBLCID	FACILITY NAME	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS
NM-0050	ARTESIA REFINERY	337	MMBTU/H	Volatile Organic Compounds (VOC)	GASEOUS FUEL COMBUSTION ONLY	0.005	LB/MMBTU	HOURLY	BACT-PSD
LA-0211	GARYVILLE REFINERY			Volatile Organic Compounds (VOC)	PROPER DESIGN, OPERATION, AND GOOD ENGINEERING PRACTICES	0.0015	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD
NM-0050	ARTESIA REFINERY	120	MMBTU/H	Volatile Organic Compounds (VOC)	GASEOUS FUEL COMBUSTION ONLY.	0.005	LB/MMBTU	HOURLY	BACT-PSD
LA-0211	GARYVILLE REFINERY	155.2	MMBTU/H EA.	Volatile Organic Compounds (VOC)	PROPER DESIGN, OPERATION, AND GOOD ENGINEERING PRACTICES	0.0015	LB/MMBTU	2 HOUR AVERAGE	BACT-PSD
LA-0211	GARYVILLE REFINERY	9.6	MM BTU/H	Volatile Organic Compounds (VOC)		0.15	MAX LB/H		BACT-PSD

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	**Heater - Refinery Process, Forced Draft**	Revision:	**3**
		Document #:	**94.2.1**
Class:	**5 MMBtu/hr to <50 MMBtu/hr Heat Input**	Date:	**08/12/94**

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. *n/d* 2. *n/s*	1. *n/d* 2. *Good Combustion Practice*[a]
NOx	1. *10 ppmv @ 3% O_2 Dry*[a,b,c,e] 2. *20 ppmv @ 3% O_2 Dry*[a,b,e]	1. *Selective Catalytic Reduction (SCR) + Low NO_x Burners*[a,b,c] 2. *Low NO_x Burners; + Flue Gas Recirculation; or Low NO_x Burners + Selective Non-Catalytic Reduction (SNCR); or Selective Catalytic Reduction(SCR)*[a,d]
SO_2	1. *Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur*[a] 2. *Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur*[a]	1. *Fuel Selection*[a] 2. *Fuel Selection*[a]
CO	1. *n/d* 2. *50 ppmv @ 3% O_2 Dry*[a,f]	1. *n/d* 2. *Good Combustion Practice*[a]
PM_{10}	1. *n/d* 2. *Natural Gas or Treated Refinery Gas Fuel*[a,b]	1. *n/d* 2. *Fuel Selection*[a,b]
NPOC	1. *n/a* 2. *n/a*	1. *n/a* 2. *n/a*

References

a. BAAQMD
b. BAAQMD A #30783
c. BAAQMD A #3318
d. BAAQMD A #8407
e. NO_x determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.
f. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	***Heater - Refinery Process, Natural or Induced Draft***	Revision:	***3***
		Document #:	***94.1.1***
Class:	***5 MMBtu/hr to <50 MMBtu/hr Heat Input***	Date:	***08/12/94***

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. *n/d* 2. *n/s*	1. *n/d* 2. *Good Combustion Practice*[a]
NOx	1. *10 ppmv @ 3%* O_2 *Dry*[a,b,c,e] 2. *25 ppmv @ 3%* O_2 *Dry*[a,b,e]	1. *Selective Catalytic Reduction (SCR) + Low* NO_x *Burners*[a,b,c] 2. *Low* NO_x *Burners; or Low* NO_x *Burners + Selective Non-Catalytic Reduction (SNCR)*[a,d]
SO_2	1. *Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur*[a] 2. *Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur*[a]	1. *Fuel Selection*[a] 2. *Fuel Selection*[a]
CO	1. *n/d* 2. *50 ppmv @ 3%* O_2 *Dry*[a,f]	1. *n/d* 2. *Good Combustion Practice*[a]
PM_{10}	1. *n/d* 2. *Natural Gas or Treated Refinery Gas Fuel*[a,b]	1. *n/d* 2. *Fuel Selection*[a,b]
NPOC	1. *n/a* 2. *n/a*	1. *n/a* 2. *n/a*

References

a. BAAQMD
b. BAAQMD A #30783
c. BAAQMD A #3318
d. BAAQMD A #8407
e. NO_x *determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.*
f. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Best Available Control Technology (BACT) Guideline

Source Category

Source:	Heater - Refinery Process	Revision:	4
		Document #:	94.3.1
Class:	≥50 MMBtu/hr Heat Input	Date:	1/14/08

Determination

POLLUTANT	BACT 1. Technologically Feasible/ Cost Effective 2. Achieved in Practice	TYPICAL TECHNOLOGY
POC	1. n/d 2. n/s	1. n/d 2. Good Combustion Practice[a]
NOx	1. *n/d* 2. 5 ppmv @ 3% O_2 Dry[c,d,e]	1. *n/d* 2. Selective Catalytic Reduction (SCR) + Low NO_x Burners[c,d]
SO_2	1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur[a] 2. Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur[a]	1. *Fuel Selection*[a] 2. Fuel Selection[a]
CO	1. n/d 2. 10 ppmv @ 3% O_2 Dry[c,d,f]	1. n/d 2. Good Combustion Practice in Conjunction w/ Selective Catalytic Reduction (SCR) System[c,d]
PM_{10}	1. n/d 2. Natural Gas or Treated Refinery Gas Fuel[a,b]	1. n/d 2. Fuel Selection[a,b]
NPOC	1. n/a 2. n/a	1. *n/a* 2. n/a

References

a. BAAQMD A #8407
b. BAAQMD A #30783
c. ARB BACT Clearinghouse, based on several South Coast AQMD projects. Recommend ammonia slip limit of 10 ppmv at 3% O_2.
d. Authority to Construct issued for BAAQMD applications 13424 & 13678 for CononcoPhillips Clean Fuels Expansion Project. For 85 MM BTU/hr furnace, the CO limit only applies at firing rates greater than 30 MM BTU/hr.
e. NO_x determination by Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.
f. CO determination by Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

Attachment H
CO Cost Effectiveness Analysis

PES Refinery
Heater Firing Rate Increase Plan Approval
CO BACT Analysis

Assumptions for all heaters:

Number of Years	10	
Interest Rate (%)	21.83	Based on 90% equity cost of the average Carlyle energy funds and 10% after tax debt cost.
Annualized Cost factor	0.253	

$$ACF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001 - Equation 2.8a

Year	*Chemical Engineering* Cost Index
2002	395.6
2012	582.2
Cost Escalation Factor	1.47

Oxidation Catalyst Costs[1]	EPA, $/cfm (2002 Basis)	EPA, $/cfm (2012 Basis)
Capital Cost for Oxidation Catalyst	35.0	51.5
O&M Cost for Oxidation Catalyst	6.0	8.8

[1] Based on EPA Air Pollution Control Technology Fact Sheet for Regenerative Incinerator (EPA-452/F-03-021). Capital costs range from $35 to $140 per cfm and O&M costs range from $6 to $20 per cfm.

	A	B	C	D	E	F	G	H	I	J	K	L
Heater	Proposed Hourly Firing Limit (MMBtu/yr)[1]	Projected Actual CO Emissions (TPY)[2]	Control Efficiency (%)	Maximum Potential Post Control Emissions (TPY)	Potential CO Reduced (TPY)	Stack Flow (ACFM)[3]	Stack Temp (°F)	Stack Flow (SCFM)	Capital Cost ($)	O&M Cost ($)	Annualized Cost[4] ($)	Cost Effectiveness ($/Ton)
Unit 231-B101	856,000	34.4	92.0	2.8	31.6	36,560	550.4	19,105	984,081	168,700	418,154	13,214
Unit 865-11H1	699,000	28.5	92.0	2.3	26.2	32,461	600.8	16,157	832,236	142,669	353,632	13,498
Unit 865-11H2	500,000	20.4	92.0	1.6	18.7	- - -	- - -	9,320	480,049	82,294	203,982	10,884
Unit 210-H101	1,643,000	66.9	92.0	5.4	61.6	76,435	640.4	36,675	1,889,120	323,849	802,722	13,035
Unit 210-H201	2,172,000	88.5	92.0	7.1	81.4	117,282	474.8	66,244	3,412,169	584,943	1,449,894	17,810
Unit 866-12H1	456,000	18.6	92.0	1.5	17.1	- - -	- - -	8,884	457,617	78,449	194,450	11,377
Unit 868-8H101	480,000	18.9	92.0	1.5	17.4	18,918	500.0	10,405	535,947	91,877	227,734	13,101
Calculation				= B * (1 - C)	= B - D			= F / ((460 + G)/(460+68))			= (I * ACF) + J	= K / E

Notes:

Trace levels of SO_2 will result in deactivation of the catalyst by sulfur-containing compounds. Oxidation catalysts are not typically installed on refinery fuel gas fired process heaters.

Oxidation catalysts typically operate at 650°F to 1,000°F. As shown above, none of the heaters in this analysis achieve stack temperatures within the typical operating range.

[1] Consistent with the proposed annual firing rate limits requested in the Plan Approval application.

[2] Consistent with the future projected actual emissions in the Plan Approval application.

[3] Stack flows (SCFM) for Unit 865-11H2 and Unit 866-12H1 Heaters were estimated using EPA Method 19 factor of 8,710 dscf/MMBtu and the proposed RACT limit.

[4] See above for details on the Annualized Cost Factor (ACF).

Attachment I
BAT Cost Effectiveness Analysis

NOx BAT Control Cost Effectiveness
Cost Effectiveness Summary

Control Option	Cost Effectiveness ($/Ton)		
	Unit 865-11H2	**Unit 866-12H1**	**Unit 868-8H101**
ULNB & SCR	38,565	40,951	38,390
SCR	37,016	39,414	36,992
ULNB	7,578	7,921	7,377
LNB & SNCR	12,424	13,322	15,892
LNB & FGR	9,790	10,534	14,197
SNCR	14,771	15,729	14,763

Assumptions for all heaters:

Number of Years (n)	10	
Interest Rate, % (i)	21.83	Based on 90% equity cost of the average Carlyle energy funds and 10% after tax debt cost.
Annualized Cost Factor (ACF)	0.253	

$$ACF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001 - Equation 2.8a

Year	*Chemical Engineering* Cost Index
1986	318.4
1991	361
2012	582.2
Cost Escalation Factor for SCR[1]	1.83
Cost Escalation Factor for LNB, SNCR, and FGR[2]	1.61

[1] Cost data from *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034 scaled from 1986 to 2012 costs using the Cost Escalation Factor.

[2] Cost data from *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034 scaled from 1991 to 2012 costs using the Cost Escalation Factor.

Source		Control Efficiency	Comment
Ultra low-NO_x burners and Selective Catalytic Reduction	ULNB & SCR	96%	Combining both removal efficiencies of ULNB and SCR.
Selective Catalytic Reduction	SCR	85%	Based on Unit 1332 Performance.
Ultra low-NO_x burners	ULNB	73%	Based on vendor experience at 0.03 lb/MMBtu.
Low-NO_x burners and Selective Non-Catalytic Reduction	LNB & SNCR	70%	Combining both removal efficiencies. Assumes 50% control efficiency for LNB and 40% control efficiency for SNCR. *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034.
Low-NO_x burners and Flue Gas Recirculation	LNB & FGR	55%	*Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034.
Selective Non-Catalytic Reduction	SNCR	40%	Heater stack temperature below 700°F results in low NOx removal efficiency. EPA Air Pollution Control Technology Fact Sheet - EPA-452/F-03-031.

Source Name	Design Capacity (MMBtu/hr)	New Firing (MMBtu/year)	NO_x Emission Rate (lb/MMBtu)	Number of Burners
Unit 865-11H2	64.2	500,000	0.113	8
Unit 866-12H1	61.2	456,000	0.113	6
Unit 868-8H101	60.0	480,000	0.113	4

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx BAT Control Cost Effectiveness

Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034
All costs are scaled from 2012 U.S. dollars using the appropriate Cost Escalation Factor.

Capital Cost of Low NO_x Burners (page 6-4 and 6-5):

$$TCI = 30{,}000 + HQ[5{,}230 - (622 \times BQ) + (26.1 \times BQ^2)]$$

Where:
TCI = Total Capital Investment
HQ = heater capacity (GJ/hr)
BQ = burner heat release rate (GJ/hr)
BQ = HQ/NB x (1.158 + 8/HQ)
NB = number of burners

Capital Cost of Ultra-low NO_x Burners:
See the "Refinery ULNB Control Costs" tab for capital cost details for Ultra-low NO_x Burners

Capital Cost of Selective Non-Catalytic Reduction (page 6-7):

$$TCI = 31{,}850(HQ)^{0.6}$$

HQ = heater capacity (GJ/hr)

Operating Cost of Selective Non-Catalytic Reduction (page 6-8):

$$NH_3\ cost\ = Q\ \times\ (lb/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{\$0.125}{lb\ NH_3}\right) \times \left(8{,}760\,\frac{hours}{year}\right)$$

Where:
Q = heater capacity, MMBtu/hr

$$Electricty\ cost = \left(\frac{0.3\ kWh}{ton\ NH_3}\right) \times \left(\frac{ton\ NH_3}{year}\right) \times \left(\frac{\$0.06}{kWh}\right)$$

Where:

$$\frac{ton\ NH_3}{year} = Q\ \times\ (lb\ NO_x/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{ton}{2000\ lb}\right) \times \left(8{,}760\,\frac{hours}{year}\right)$$

Capital Cost of Selective Catalytic Reduction (page 6-8):

$$TCI = 1{,}373{,}000 \times \left(\frac{Q}{48.5}\right)^{0.6} + 49{,}000 \times \left(\frac{Q}{485}\right)$$

Where:
Q = heater capacity, MMBtu/hr

Operating Cost of Selective Catalytic Reduction (page 6-9):

$$NH_3\ cost = Q\ \times\ (lb/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{\$0.125}{lb\ NH_3}\right) \times \left(\frac{8{,}760\ hours}{year}\right)$$

Where:
Q = heater capacity, MMBtu/hr
Note the capacity factor has been assumed to be equal to 1; therefore, the capacity factor term has been omitted.

$$Catalyst\ Replacement\ Cost = 49{,}000 \times \frac{Q}{48.5}/5\ years$$

$$Electricty\ cost = \left(\frac{0.3\ kWh}{ton\ NH_3}\right) \times \left(\frac{ton\ NH_3}{year}\right) \times \left(\frac{\$0.06}{kWh}\right)$$

Where:

$$\frac{ton\ NH_3}{year} = Q\ \times\ (lb\ NO_x/MMBtu) \times \left(\frac{1\ mole\ NO_x}{46\ lb\ NO_x}\right) \times \left(\frac{17\ lb\ NH_3}{1\ mole\ NH_3}\right) \times \left(\frac{1\ mole\ NH_3}{1\ mole\ NO_x}\right) \times \left(\frac{ton}{2000\ lb}\right) \times \left(8{,}760\,\frac{hours}{year}\right)$$

Capital Cost of Flue Gas Recirculation (page 6-9):

$$TCI = 12{,}800(HQ)^{0.6}$$

Where:
HQ = heater capacity (GJ/hr)

Operating Cost of Flue Gas Recirculation (page 6-10):

$$Electricty\ cost = (motor\ hp) \times \left(\frac{0.75\ kW}{hp}\right) \times \left(\frac{8{,}760\ hours}{year}\right) \times \left(\frac{\$0.06}{kWh}\right)$$

Where:
motor hp = FGR fan motor horsepower, (1/5) x (Q)
Q = heater capacity, MMBtu/hr

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx BAT Control Cost Effectiveness

Ultra Low NO_x Burner Costs

Economic Data	Heater Fired Duty (MMBtu/hr)	Number of Burners	Burner Heat Release (MMBtu/hr/burner)	Base Year ULNB Cost ($/burner)	Normalized Cost ($/MMBtu/hr)
1332 H-400/H-401 Heater	419	54	7.8	$50,000	$6,444
137 F-3 Heater	60	4	15	$80,500	$5,367
				Average	$5,905

SOURCE NAME	**Rated Capacity (MMBtu/hr)**	**ULNB Capital Cost Using ($/MMBtu/hr)**	**ULNB Total Capital Investment**
Unit 865-11H2	64.2	$379,120	$559,581
Unit 866-12H1	61.2	$361,404	$0
Unit 868-8H101	60.0	$354,317	$0

PES Refinery
Heater Firing Rate Increase Plan Approval
Unit 865-11H2 BAT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	New Firing (MMBtu/yr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ New Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	500,000	0.113	28.3	96%	1.1	27.1	3,631,525	125,523	1,046,078	38,565
SCR	500,000	0.113	28.3	85%	4.2	24.0	3,071,944	110,135	888,841	37,016
ULNB	500,000	0.113	28.3	73%	7.5	20.8	559,581	15,388	157,237	7,578
LNB & SNCR	500,000	0.113	28.3	70%	8.5	19.8	857,483	28,316	245,679	12,424
LNB & FGR	500,000	0.113	28.3	55%	12.7	15.5	512,272	22,250	152,106	9,790
SNCR	500,000	0.113	28.3	40%	17.0	11.3	577,165	20,607	166,913	14,771
Calculation			= A * B / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Notes:
[1] Unit 865-11H2 is projected to be above PADEP presumptive RACT firing limits and assumed NO_x emission rate limit of 0.113 lb/MMBtu is used.
[2] See "BAT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx BAT Control Cost Effectiveness

Source	**Unit 865-11H2**	
Control	**ULNB & SCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Rated Heat Input	**500,000**	**MMBtu/yr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**28.3**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**96%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS - ULNB	
Purchased Equipment Costs	
Equipment Cost (EC)	379,120
Instrumentation (10% of EC)	37,912
Sales taxes (5% of EC)	18,956
Freight (8% of EC)	30,330
Subtotal - Purchased Equipment Costs (PEC)	**466,317**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - ULNB	**466,317**
INDIRECT INSTALLATION COSTS - ULNB	
Engineering Costs (5% of PEC)	23,316
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	46,632
Start-up (1% of PEC)	4,663
Performance Test (1% of PEC)	4,663
Contingency (3% of PEC)	13,990
TOTAL INDIRECT COSTS, IC	**93,263**
DIRECT COSTS - SCR	
Purchased Equipment Costs	
Equipment Cost (EC)	2,982,470
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,982,470**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SCR	**2,982,470**
INDIRECT INSTALLATION COSTS - SCR	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	89,474
TOTAL INDIRECT COSTS, IC - SCR	**89,474**
TOTAL CAPITAL INVESTMENT (TCI) - ULNB	**559,581**
TOTAL CAPITAL INVESTMENT (TCI) - SCR	**3,071,944**
TOTAL CAPITAL INVESTMENT (TCI)	**3,631,525**

PES Refinery
Heater Firing Rate Increase Plan Approval
NOx BAT Control Cost Effectiveness

COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		99,867
		99,867
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,735
Catalyst Replacement Cost		20,921
Electricity Cost		0.3
Subtotal - Utilities		**25,656**
TOTAL ANNUAL DIRECT COSTS[a]		**125,523**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**125,523**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		3,631,525
TOTAL ANNUAL CAPITAL REQUIREMENT		**920,555**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**1,046,078**

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Source	**Unit 865-11H2**	
Control	**SCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Rated Heat Input	**500,000**	**MMBtu/yr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**28.3**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	2,982,470
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,982,470**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**2,982,470**
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	89,474
TOTAL INDIRECT COSTS, IC	**89,474**
TOTAL CAPITAL INVESTMENT (TCI)	**3,071,944**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		84,478
		84,478
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,735
Catalyst Replacement Cost		20,921
Electricity Cost		0.3
Subtotal - Utilities		**25,656**
TOTAL ANNUAL DIRECT COSTS[a]		**110,135**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**110,135**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		3,071,944
TOTAL ANNUAL CAPITAL REQUIREMENT		**778,707**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**888,841**

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Source	**Unit 865-11H2**	
Control	**ULNB**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Rated Heat Input	**500,000**	**MMBtu/yr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**28.3**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**73%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:		COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	379,120
	Instrumentation (10% of EC)	37,912
	Sales taxes (5% of EC)	18,956
	Freight (8% of EC)	30,330
	Subtotal - Purchased Equipment Costs (PEC)	**466,317**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**466,317**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	23,316
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	46,632
	Start-up (1% of PEC)	4,663
	Performance Test (1% of PEC)	4,663
	Contingency (3% of PEC)	13,990
TOTAL INDIRECT COSTS, IC		**93,263**
TOTAL CAPITAL INVESTMENT (TCI)		**559,581**

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COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			15,388
			15,388
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
None			
Subtotal - Utilities			**0.0**
TOTAL ANNUAL DIRECT COSTS[a]			**15,388**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**15,388**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			559,581
TOTAL ANNUAL CAPITAL REQUIREMENT			**141,848**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**157,237**

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Source	**Unit 865-11H2**	
Control	**LNB & SNCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Rated Heat Input	**500,000**	**MMBtu/yr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**28.3**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	189,917
Instrumentation (10% of EC)	18,992
Sales taxes (5% of EC)	9,496
Freight (8% of EC)	15,193
Subtotal - Purchased Equipment Costs (PEC)	**233,598**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**233,598**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	11,680
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	23,360
Start-up (1% of PEC)	2,336
Performance Test (1% of PEC)	2,336
Contingency (3% of PEC)	7,008
TOTAL INDIRECT COSTS, IC - LNB	**46,720**
DIRECT COSTS - SNCR	
Purchased Equipment Costs	
Equipment Cost (EC)	560,355
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**560,355**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR	**560,355**
INDIRECT INSTALLATION COSTS - SNCR	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	16,811
TOTAL INDIRECT COSTS, IC - SNCR	**16,811**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**280,318**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR	**577,165**
TOTAL CAPITAL INVESTMENT (TCI)	**857,483**

COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		23,581
		23,581
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,735
Electricity Cost		0.3
Subtotal - Utilities		**4,735**
TOTAL ANNUAL DIRECT COSTS[a]		**28,316**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**28,316**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		857,483
TOTAL ANNUAL CAPITAL REQUIREMENT		**217,363**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**245,679**

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Source	**Unit 865-11H2**	
Control	**LNB & FGR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Rated Heat Input	**500,000**	**MMBtu/yr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**28.3**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**55%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS - LNB		
	Purchased Equipment Costs	
	Equipment Cost (EC)	189,917
	Instrumentation (10% of EC)	18,992
	Sales taxes (5% of EC)	9,496
	Freight (8% of EC)	15,193
	Subtotal - Purchased Equipment Costs (PEC)	**233,598**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB		**233,598**
INDIRECT INSTALLATION COSTS - LNB		
	Engineering Costs (5% of PEC)	11,680
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	23,360
	Start-up (1% of PEC)	2,336
	Performance Test (1% of PEC)	2,336
	Contingency (3% of PEC)	7,008
TOTAL INDIRECT COSTS, IC - LNB		**46,720**
DIRECT COSTS - FGR		
	Purchased Equipment Costs	
	Equipment Cost (EC)	225,197
	Instrumentation (10% of EC)	- - -
	Sales taxes (5% of EC)	- - -
	Freight (8% of EC)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**225,197**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - FGR		**225,197**
INDIRECT INSTALLATION COSTS - FGR		
	Engineering Costs (5% of PEC)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	- - -
	Start-up (1% of PEC)	- - -
	Performance Test (1% of PEC)	- - -
	Contingency (3% of PEC)	6,756
TOTAL INDIRECT COSTS, IC - FGR		**6,756**
TOTAL CAPITAL INVESTMENT (TCI) - LNB		**280,318**
TOTAL CAPITAL INVESTMENT (TCI) - FGR		**231,953**
TOTAL CAPITAL INVESTMENT (TCI)		**512,272**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		14,087
		14,087
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Electricity Cost		8,163
Subtotal - Utilities		**8,163**
TOTAL ANNUAL DIRECT COSTS[a]		**22,250**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**22,250**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		512,272
TOTAL ANNUAL CAPITAL REQUIREMENT		**129,856**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**152,106**

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Source	**Unit 865-11H2**	
Control	**SNCR**	
Rated Heat Input	**64.2**	**MMBtu/hr**
Rated Heat Input	**500,000**	**MMBtu/yr**
Number of Burners	**8.0**	**Burners**
Baseline Actual Emissions	**28.3**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**67.7**	**GJ/hr**
Burner Heat Release Rate	**10.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	560,355
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**560,355**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**560,355**
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	16,811
TOTAL INDIRECT COSTS, IC	**16,811**
TOTAL CAPITAL INVESTMENT (TCI)	**577,165**

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COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			15,872
			15,872
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,735
Electricity Cost			0.3
Subtotal - Utilities			**4,735**
TOTAL ANNUAL DIRECT COSTS[a]			**20,607**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**20,607**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			577,165
TOTAL ANNUAL CAPITAL REQUIREMENT			**146,306**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**166,913**

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Unit 866-12H1 BAT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	New Firing (MMBtu/yr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ New Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	456,000	0.113	25.8	96%	1.0	24.7	3,518,199	121,208	1,013,036	40,951
SCR	456,000	0.113	25.8	85%	3.9	21.9	2,984,767	106,538	863,147	39,414
ULNB	456,000	0.113	25.8	73%	6.8	18.9	533,432	14,669	149,889	7,921
LNB & SNCR	456,000	0.113	25.8	70%	7.7	18.0	838,966	27,585	240,255	13,322
LNB & FGR	456,000	0.113	25.8	55%	11.6	14.2	503,525	21,628	149,267	10,534
SNCR	456,000	0.113	25.8	40%	15.5	10.3	560,828	19,936	162,101	15,729
Calculation			= A * B / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Notes:
[1] Unit 866-12H1 is projected to be above PADEP presumptive RACT firing limits and assumed NO_x emission rate limit of 0.113 lb/MMBtu is used.
[2] See "BAT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

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Source	**Unit 866-12H1**	
Control	**ULNB & SCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Rated Heat Input	**456,000**	**MMBtu/yr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**25.8**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**96%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - ULNB	
Purchased Equipment Costs	
Equipment Cost (EC)	361,404
Instrumentation (10% of EC)	36,140
Sales taxes (5% of EC)	18,070
Freight (8% of EC)	28,912
Subtotal - Purchased Equipment Costs (PEC)	**444,527**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - ULNB	**444,527**
INDIRECT INSTALLATION COSTS - ULNB	
Engineering Costs (5% of PEC)	22,226
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	44,453
Start-up (1% of PEC)	4,445
Performance Test (1% of PEC)	4,445
Contingency (3% of PEC)	13,336
TOTAL INDIRECT COSTS, IC	**88,905**
DIRECT COSTS - SCR	
Purchased Equipment Costs	
Equipment Cost (EC)	2,897,832
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,897,832**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SCR	**2,897,832**
INDIRECT INSTALLATION COSTS - SCR	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	86,935
TOTAL INDIRECT COSTS, IC - SCR	**86,935**
TOTAL CAPITAL INVESTMENT (TCI) - ULNB	**533,432**
TOTAL CAPITAL INVESTMENT (TCI) - SCR	**2,984,767**
TOTAL CAPITAL INVESTMENT (TCI)	**3,518,199**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		96,750
		96,750
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,513
Catalyst Replacement Cost		19,943
Electricity Cost		0.3
Subtotal - Utilities		**24,457**
TOTAL ANNUAL DIRECT COSTS		**121,208**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**121,208**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		3,518,199
TOTAL ANNUAL CAPITAL REQUIREMENT		**891,828**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**1,013,036**

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Source	**Unit 866-12H1**	
Control	**SCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Rated Heat Input	**456,000**	**MMBtu/yr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**25.8**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	2,897,832
	Instrumentation (10% of EC)	- - -
	Sales taxes (5% of EC)	- - -
	Freight (8% of EC)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**2,897,832**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**2,897,832**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	- - -
	Start-up (1% of PEC)	- - -
	Performance Test (1% of PEC)	- - -
	Contingency (3% of PEC)	86,935
TOTAL INDIRECT COSTS, IC		**86,935**
TOTAL CAPITAL INVESTMENT (TCI)		**2,984,767**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		82,081
		82,081
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,513
Catalyst Replacement Cost		19,943
Electricity Cost		0.3
Subtotal - Utilities		**24,457**
TOTAL ANNUAL DIRECT COSTS[a]		**106,538**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**106,538**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		2,984,767
TOTAL ANNUAL CAPITAL REQUIREMENT		**756,608**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**863,147**

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Source	**Unit 866-12H1**	
Control	**ULNB**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Rated Heat Input	**456,000**	**MMBtu/yr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**25.8**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**73%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	361,404
	Instrumentation (10% of EC)	36,140
	Sales taxes (5% of EC)	18,070
	Freight (8% of EC)	28,912
	Subtotal - Purchased Equipment Costs (PEC)	**444,527**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**444,527**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	22,226
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	44,453
	Start-up (1% of PEC)	4,445
	Performance Test (1% of PEC)	4,445
	Contingency (3% of PEC)	13,336
TOTAL INDIRECT COSTS, IC		**88,905**
TOTAL CAPITAL INVESTMENT (TCI)		**533,432**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		14,669
		14,669
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
None		
Subtotal - Utilities		**0.0**
TOTAL ANNUAL DIRECT COSTS[a]		**14,669**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**14,669**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		533,432
TOTAL ANNUAL CAPITAL REQUIREMENT		**135,220**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**149,889**

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Source	**Unit 866-12H1**	
Control	**LNB & SNCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Rated Heat Input	**456,000**	**MMBtu/yr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**25.8**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	188,440
Instrumentation (10% of EC)	18,844
Sales taxes (5% of EC)	9,422
Freight (8% of EC)	15,075
Subtotal - Purchased Equipment Costs (PEC)	**231,781**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**231,781**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	11,589
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	23,178
Start-up (1% of PEC)	2,318
Performance Test (1% of PEC)	2,318
Contingency (3% of PEC)	6,953
TOTAL INDIRECT COSTS, IC - LNB	**46,356**
DIRECT COSTS - SNCR	
Purchased Equipment Costs	
Equipment Cost (EC)	544,494
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**544,494**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR	**544,494**
INDIRECT INSTALLATION COSTS - SNCR	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	16,335
TOTAL INDIRECT COSTS, IC - SNCR	**16,335**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**278,137**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR	**560,828**
TOTAL CAPITAL INVESTMENT (TCI)	**838,966**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		23,072
		23,072
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,513
Electricity Cost		0.3
Subtotal - Utilities		**4,514**
TOTAL ANNUAL DIRECT COSTS[a]		**27,585**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**27,585**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		838,966
TOTAL ANNUAL CAPITAL REQUIREMENT		**212,669**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**240,255**

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Source	**Unit 866-12H1**	
Control	**LNB & FGR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Rated Heat Input	**456,000**	**MMBtu/yr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**25.8**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**55%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS - LNB		
	Purchased Equipment Costs	
	Equipment Cost (EC)	188,440
	Instrumentation (10% of EC)	18,844
	Sales taxes (5% of EC)	9,422
	Freight (8% of EC)	15,075
	Subtotal - Purchased Equipment Costs (PEC)	**231,781**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB		**231,781**
INDIRECT INSTALLATION COSTS - LNB		
	Engineering Costs (5% of PEC)	11,589
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	23,178
	Start-up (1% of PEC)	2,318
	Performance Test (1% of PEC)	2,318
	Contingency (3% of PEC)	6,953
TOTAL INDIRECT COSTS, IC - LNB		**46,356**
DIRECT COSTS - FGR		
	Purchased Equipment Costs	
	Equipment Cost (EC)	218,823
	Instrumentation (10% of EC)	- - -
	Sales taxes (5% of EC)	- - -
	Freight (8% of EC)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**218,823**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - FGR		**218,823**
INDIRECT INSTALLATION COSTS - FGR		
	Engineering Costs (5% of PEC)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	- - -
	Start-up (1% of PEC)	- - -
	Performance Test (1% of PEC)	- - -
	Contingency (3% of PEC)	6,565
TOTAL INDIRECT COSTS, IC - FGR		**6,565**
TOTAL CAPITAL INVESTMENT (TCI) - LNB		**278,137**
TOTAL CAPITAL INVESTMENT (TCI) - FGR		**225,388**
TOTAL CAPITAL INVESTMENT (TCI)		**503,525**

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COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			13,847
			13,847
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Electricity Cost			7,781
Subtotal - Utilities			**7,781**
TOTAL ANNUAL DIRECT COSTS[a]			**21,628**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**21,628**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			503,525
TOTAL ANNUAL CAPITAL REQUIREMENT			**127,639**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**149,267**

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Source	**Unit 866-12H1**	
Control	**SNCR**	
Rated Heat Input	**61.2**	**MMBtu/hr**
Rated Heat Input	**456,000**	**MMBtu/yr**
Number of Burners	**6.0**	**Burners**
Baseline Actual Emissions	**25.8**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**64.6**	**GJ/hr**
Burner Heat Release Rate	**13.8**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS	
Purchased Equipment Costs	
Equipment Cost (EC)	544,494
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**544,494**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)	**544,494**
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	16,335
TOTAL INDIRECT COSTS, IC	**16,335**
TOTAL CAPITAL INVESTMENT (TCI)	**560,828**

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COST COMPONENT:		COST ($)
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		15,423
		15,423
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,513
Electricity Cost		0.3
Subtotal - Utilities		**4,514**
TOTAL ANNUAL DIRECT COSTS[a]		**19,936**

COST COMPONENT:		COST ($)
TOTAL ANNUAL O&M COSTS		**19,936**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		560,828
TOTAL ANNUAL CAPITAL REQUIREMENT		**142,164**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**162,101**

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Unit 868-8H101 BAT Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J
Control Option	New Firing (MMBtu/yr)	Current Emission Rate (lb/MMBtu)[1]	Potential Emissions (TPY)	Control Efficiency (%)	Maximum Post Control Emissions @ New Firing (TPY)	Potential NO_x Reduced (TPY)	2012 Total Capital Cost ($)	2012 O&M Cost ($)	2012 Annualized Cost[2] ($)	2012 Cost Effectiveness ($/Ton)
ULNB & SCR	480,000	0.113	27.1	96%	1.1	26.0	3,472,395	119,468	999,686	38,390
SCR	480,000	0.113	27.1	85%	4.1	23.1	2,949,422	105,087	852,736	36,992
ULNB	480,000	0.113	27.1	73%	7.2	19.9	522,973	14,382	146,950	7,377
LNB & SNCR	480,000	0.113	27.1	70%	8.1	19.0	1,057,946	33,519	301,697	15,892
LNB & FGR	480,000	0.113	27.1	55%	12.2	14.9	726,468	27,607	211,759	14,197
SNCR	480,000	0.113	27.1	40%	16.3	10.8	554,204	19,666	160,151	14,763
Calculation			= A * B / 2000		= C * (1 - D)	= C - E			= (G * ACF) + H	= I / F

Notes:
[1] Unit 868-8H101 is projected to be above PADEP presumptive RACT firing limits and assumed NO_x emission rate limit of 0.113 lb/MMBtu is used.
[2] See "BAT Cost Summary" tab for details on the Annualized Cost Factor (ACF).

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Source	**Unit 868-8H101**	
Control	**ULNB & SCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Rated Heat Input	**480,000**	**MMBtu/yr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**27.1**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**96%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	**COST ($)**
DIRECT COSTS - ULNB	
Purchased Equipment Costs	
Equipment Cost (EC)	354,317
Instrumentation (10% of EC)	35,432
Sales taxes (5% of EC)	17,716
Freight (8% of EC)	28,345
Subtotal - Purchased Equipment Costs (PEC)	**435,810**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - ULNB	**435,810**
INDIRECT INSTALLATION COSTS - ULNB	
Engineering Costs (5% of PEC)	21,791
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	43,581
Start-up (1% of PEC)	4,358
Performance Test (1% of PEC)	4,358
Contingency (3% of PEC)	13,074
TOTAL INDIRECT COSTS, IC	**87,162**
DIRECT COSTS - SCR	
Purchased Equipment Costs	
Equipment Cost (EC)	2,863,517
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**2,863,517**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SCR	**2,863,517**
INDIRECT INSTALLATION COSTS - SCR	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	85,906
TOTAL INDIRECT COSTS, IC - SCR	**85,906**
TOTAL CAPITAL INVESTMENT (TCI) - ULNB	**522,973**
TOTAL CAPITAL INVESTMENT (TCI) - SCR	**2,949,422**
TOTAL CAPITAL INVESTMENT (TCI)	**3,472,395**

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COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			95,491
			95,491
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,425
Catalyst Replacement Cost			19,552
Electricity Cost			0.3
Subtotal - Utilities			**23,978**
TOTAL ANNUAL DIRECT COSTS"			**119,468**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**119,468**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			3,472,395
TOTAL ANNUAL CAPITAL REQUIREMENT			**880,217**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**999,686**

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Source	**Unit 868-8H101**	
Control	**SCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Rated Heat Input	**480,000**	**MMBtu/yr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**27.1**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**85%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	2,863,517
	Instrumentation (10% of EC)	- - -
	Sales taxes (5% of EC)	- - -
	Freight (8% of EC)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**2,863,517**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**2,863,517**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	- - -
	Start-up (1% of PEC)	- - -
	Performance Test (1% of PEC)	- - -
	Contingency (3% of PEC)	85,906
TOTAL INDIRECT COSTS, IC		**85,906**
TOTAL CAPITAL INVESTMENT (TCI)		**2,949,422**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		81,109
		81,109
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,425
Catalyst Replacement Cost		19,552
Electricity Cost		0.3
Subtotal - Utilities		**23,978**
TOTAL ANNUAL DIRECT COSTS[a]		**105,087**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**105,087**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		2,949,422
TOTAL ANNUAL CAPITAL REQUIREMENT		**747,649**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**852,736**

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Source	**Unit 868-8H101**	
Control	**ULNB**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Rated Heat Input	**480,000**	**MMBtu/yr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**27.1**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**73%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

	COST COMPONENT:	**COST ($)**
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	354,317
	Instrumentation (10% of EC)	35,432
	Sales taxes (5% of EC)	17,716
	Freight (8% of EC)	28,345
	Subtotal - Purchased Equipment Costs (PEC)	**435,810**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**435,810**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	21,791
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	43,581
	Start-up (1% of PEC)	4,358
	Performance Test (1% of PEC)	4,358
	Contingency (3% of PEC)	13,074
TOTAL INDIRECT COSTS, IC		**87,162**
TOTAL CAPITAL INVESTMENT (TCI)		**522,973**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		14,382
		14,382
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
None		
Subtotal - Utilities		**0.0**
TOTAL ANNUAL DIRECT COSTS[a]		**14,382**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**14,382**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		522,973
TOTAL ANNUAL CAPITAL REQUIREMENT		**132,568**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**146,950**

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Source	**Unit 868-8H101**	
Control	**LNB & SNCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Rated Heat Input	**480,000**	**MMBtu/yr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**27.1**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**70%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST ($)
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	341,289
Instrumentation (10% of EC)	34,129
Sales taxes (5% of EC)	17,064
Freight (8% of EC)	27,303
Subtotal - Purchased Equipment Costs (PEC)	**419,785**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**419,785**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	20,989
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	41,979
Start-up (1% of PEC)	4,198
Performance Test (1% of PEC)	4,198
Contingency (3% of PEC)	12,594
TOTAL INDIRECT COSTS, IC - LNB	**83,957**
DIRECT COSTS - SNCR	
Purchased Equipment Costs	
Equipment Cost (EC)	538,062
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**538,062**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - SNCR	**538,062**
INDIRECT INSTALLATION COSTS - SNCR	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	16,142
TOTAL INDIRECT COSTS, IC - SNCR	**16,142**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**503,742**
TOTAL CAPITAL INVESTMENT (TCI) - SNCR	**554,204**
TOTAL CAPITAL INVESTMENT (TCI)	**1,057,946**

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COST COMPONENT:		**COST ($)**
ANNUAL DIRECT COSTS		
Operation and Maintenance Labor		
Maintenance Labor and Material (2.75% of TCI)		29,094
		29,094
Annualized Cost Factor		
Replacement Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
Replacement cost		
Subtotal - Operation and Maintenance Labor		
Utilities		
Ammonia Cost		4,425
Electricity Cost		0.3
Subtotal - Utilities		**4,425**
TOTAL ANNUAL DIRECT COSTS[a]		**33,519**

COST COMPONENT:		**COST ($)**
TOTAL ANNUAL O&M COSTS		**33,519**
Annualized Cost Factor		
Equipment Life (years) =	10	
Interest Rate (%) =	21.83	
Annualized Cost Factor		0.25
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		1,057,946
TOTAL ANNUAL CAPITAL REQUIREMENT		**268,179**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***		**301,697**

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Source	**Unit 868-8H101**	
Control	**LNB & FGR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Rated Heat Input	**480,000**	**MMBtu/yr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**27.1**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**55%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

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COST COMPONENT:	**COST ($)**
DIRECT COSTS - LNB	
Purchased Equipment Costs	
Equipment Cost (EC)	341,289
Instrumentation (10% of EC)	34,129
Sales taxes (5% of EC)	17,064
Freight (8% of EC)	27,303
Subtotal - Purchased Equipment Costs (PEC)	**419,785**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - LNB	**419,785**
INDIRECT INSTALLATION COSTS - LNB	
Engineering Costs (5% of PEC)	20,989
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	41,979
Start-up (1% of PEC)	4,198
Performance Test (1% of PEC)	4,198
Contingency (3% of PEC)	12,594
TOTAL INDIRECT COSTS, IC - LNB	**83,957**
DIRECT COSTS - FGR	
Purchased Equipment Costs	
Equipment Cost (EC)	216,239
Instrumentation (10% of EC)	- - -
Sales taxes (5% of EC)	- - -
Freight (8% of EC)	- - -
Subtotal - Purchased Equipment Costs (PEC)	**216,239**
Direct Installation Costs (Based on Vendor Discussion)	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	- - -
Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC) - FGR	**216,239**
INDIRECT INSTALLATION COSTS - FGR	
Engineering Costs (5% of PEC)	- - -
Construct. & Field Expenses (Included in above costs)	- - -
Contractor Fees (10% of PEC)	- - -
Start-up (1% of PEC)	- - -
Performance Test (1% of PEC)	- - -
Contingency (3% of PEC)	6,487
TOTAL INDIRECT COSTS, IC - FGR	**6,487**
TOTAL CAPITAL INVESTMENT (TCI) - LNB	**503,742**
TOTAL CAPITAL INVESTMENT (TCI) - FGR	**222,726**
TOTAL CAPITAL INVESTMENT (TCI)	**726,468**

COST COMPONENT:			**COST ($)**
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			19,978
			19,978
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Electricity Cost			7,629
Subtotal - Utilities			**7,629**
TOTAL ANNUAL DIRECT COSTS[a]			**27,607**

COST COMPONENT:			**COST ($)**
TOTAL ANNUAL O&M COSTS			**27,607**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			726,468
TOTAL ANNUAL CAPITAL REQUIREMENT			**184,152**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**211,759**

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Source	**Unit 868-8H101**	
Control	**SNCR**	
Rated Heat Input	**60.0**	**MMBtu/hr**
Rated Heat Input	**480,000**	**MMBtu/yr**
Number of Burners	**4.0**	**Burners**
Baseline Actual Emissions	**27.1**	**tpy**
Current Emission Rate	**0.113**	**lb/MMBtu**
Control Efficiency	**40%**	
Heater Capacity	**63.3**	**GJ/hr**
Burner Heat Release Rate	**20.3**	**GJ/hr**

Evaluated at New Firing Limit at 2012 Cost and Efficiencies
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	COST COMPONENT:	COST ($)
DIRECT COSTS		
	Purchased Equipment Costs	
	Equipment Cost (EC)	538,062
	Instrumentation (10% of EC)	- - -
	Sales taxes (5% of EC)	- - -
	Freight (8% of EC)	- - -
	Subtotal - Purchased Equipment Costs (PEC)	**538,062**
	Direct Installation Costs (Based on Vendor Discussion)	
	Foundations & supports; handling & erection; electrical; piping; etc.	0
	Site Preparation / Buildings- Included above	- - -
	Subtotal - Direct Installation Costs	**0**
TOTAL DIRECT COSTS (TDC)		**538,062**
INDIRECT INSTALLATION COSTS		
	Engineering Costs (5% of PEC)	- - -
	Construct. & Field Expenses (Included in above costs)	- - -
	Contractor Fees (10% of PEC)	- - -
	Start-up (1% of PEC)	- - -
	Performance Test (1% of PEC)	- - -
	Contingency (3% of PEC)	16,142
TOTAL INDIRECT COSTS, IC		**16,142**
TOTAL CAPITAL INVESTMENT (TCI)		**554,204**

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COST COMPONENT:			COST ($)
ANNUAL DIRECT COSTS			
Operation and Maintenance Labor			
Maintenance Labor and Material (2.75% of TCI)			15,241
			15,241
Annualized Cost Factor			
	Replacement Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
Replacement cost			
Subtotal - Operation and Maintenance Labor			
Utilities			
Ammonia Cost			4,425
Electricity Cost			0.3
Subtotal - Utilities			**4,425**
TOTAL ANNUAL DIRECT COSTS[a]			**19,666**

COST COMPONENT:			COST ($)
TOTAL ANNUAL O&M COSTS			**19,666**
Annualized Cost Factor			
	Equipment Life (years) =	10	
	Interest Rate (%) =	21.83	
Annualized Cost Factor			0.25
CAPITAL RECOVERY COSTS			
TOTAL CAPITAL REQUIREMENT			554,204
TOTAL ANNUAL CAPITAL REQUIREMENT			**140,485**
TOTAL ANNUALIZED COST ***(Total annual O&M cost and annualized capital cost)***			**160,151**